

APPENDIX D

TECHNICAL REPORT ON

PROJECT DESCRIPTION

BP CHERRY POINT COGENERATION PROJECT

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013-1421 |

EXECUTIVE SUMMARY

The proposed BP Cherry Point Cogeneration Project (Cogeneration Project) would be a combined cycle cogeneration (steam and electricity) facility located at the BP Cherry Point Refinery (Refinery), which is near Ferndale and Blaine in northwestern Whatcom County, Washington. The proposed Cogeneration Project would use a state-of-the-art high-efficiency power generation system and use clean-burning natural gas. The plant would produce a nominal 720 megawatts (MW) and would be configured with three combustion gas turbines generators (CGTs). Each of the gas turbines would be equipped with a heat recovery steam generator (HRSG) with duct-firing capability. Steam produced from the HRSGs would be combined and sent to a single steam turbine-driven electric generator (STG) with [process](#) extraction and ~~air~~-condensing capability.

The entire project, including the generation plant and support facilities, the new transmission line, natural gas and water supply pipelines, and construction laydown areas would be on BP owned property. The proposed Cogeneration Project would be consistent with existing land uses in the surrounding area. The Cogeneration Project would be adjacent to the Refinery. The Refinery and surrounding properties owned by BP are zoned Heavy Impact Industrial and Light Industrial and are contained within the Cherry Point Major Industrial Urban Grown Area/Port Industrial Zone of the Whatcom County Comprehensive Plan issued May 20, 1997.

Cogeneration offers increased thermal efficiencies that do not otherwise exist for electrical power generation. The Cogeneration Project provides steam to the Refinery, which will increase efficiency and reduce the consumption of natural gas. This would allow the shutdown of older, less efficient boilers used for Refinery steam supply, and would partially offset emissions from the Cogeneration Project.

The Cogeneration Project would also eliminate the need for the Refinery to use diesel or gas turbine generators to supply part of its electricity needs as it has intermittently since December 2000. [The only equipment used in the proposed Cogeneration Project that use diesel fuel would be the emergency diesel generator and diesel engine driven fire water pump would not use backup fuels.](#)

The Cogeneration Project would minimize fresh water consumption by using ~~an Air Cooled Condenser (ACC) or~~ recycled industrial water ~~instead of fresh water for its~~ cooling systems. ~~The small amount of~~ wastewater produced by the Cogeneration Project would be generated from ~~boiler cooling tower~~ blow-down, raw water demineralization system, [refinery condensate treatment](#), sanitary wastes, and storm water runoff from Cogeneration Project secondary containment areas for spill protection. These wastewaters, except for sanitary waste [and spent pre-coat filter material](#), would be sent to the Refinery wastewater treatment system. Treated Refinery wastewaters are discharged to the Strait of Georgia. Sanitary wastes would be sent to the Birch Bay Water and Sewer District (District). [Spent pre-coat filter material would be collected in a separate tank, dewatered to the refinery waste water treatment system, and disposed of properly with other primary sludge generated within the Refinery.](#)

Stormwater runoff from the areas of the Cogeneration Project other than secondary containment areas would be collected and routed to an oil/water separator to ensure no trace oil is present, and then a detention pond for clarification prior to discharge to nearby wetlands.

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DRAWING	SK-BE7608-MD-0006

ATTACHMENTS

Attachment A Industry Codes and Standards

LIST OF ACRONYMS

ACC	Air Cooled Condenser
<u>BACT</u>	<u>Best Available Control Technology</u>
BFW	Boiler Feed Water
<u>Bhp</u>	<u>Brake Horsepower</u>
BMP	Best Management Practices
BMS	Burner Management System
BPA	Bonneville Power Administration
<u>CFR</u>	<u>Code of Federal Register</u>
CCWS	Closed Cooling Water System
CEMS	Continuous Emissions Monitoring System
CGT	Combustion Gas Turbine
CO	Carbon Monoxide

CO₂	Carbon Dioxide
Dc	Direct Current
CRT	Cathode Ray Tube Display
DAS	Data Acquisition System
DCS	Distributed Control System
District	Birch Bay Water and Sewer District
E	East
EPC	Engineering, Procurement and Construction
EH&S	Environmental Health and Safety
F	Fahrenheit
ft³	Cubic Feet
Gal	Gallon
GE	General Electric
GPM	Gallons per Minute
H₂SO₄	Sulfuric Acid
HP	High Pressure
HRSG	Heat Recovery Steam Generator
IP	Intermediate Pressure
ISO	International Standards Organization
Kpph	Thousands of pounds per hour
KV	Kilovolt
Lbs	Pounds
LP	Low Pressure
MCC	Motor Control Center
MSDS	Material Safety Data Sheet
MVA	Mega volt-amps
MW	Megawatt
N	North
NDE	Non-destructive Examination
NH ₃	Ammonia
NO _x	Oxides of Nitrogen
NPDES	National Pollution Discharge Elimination System
NTU	Nephelometric Turbidity Unit
O ₂	Oxygen
OSHA	Occupational Safety and Health Administration
OWS	Oil-Water Sewer
PEECC	Packaged Electronic and Electrical Control Compartment
PF	Power Factor
PLC	Programmable Logic Controller
PM₁₀	Particulate matter less than 10 microns
Ppmvd	Parts per million by volume on a dry basis
PSD	Prevention of Significant Deterioration
PSIA	Pounds per square inch absolute
PSIG	Pounds per Square Inch
PUD	Public Utility District
QA	Quality Assurance
QC	Quality Control
Rev	Revision
S	South
SCR	Selective Catalytic Reduction
SPCC	Spill Prevention, Control, and Countermeasure Plan

SO₂	Sulfur dioxide
SO₃	Sulfur trioxide
SO _x	Oxides of Sulfur
STG	Steam Turbine Generator
SWPPP	Stormwater Pollution Prevention Plan
RBFW	Return Boiler Feed Water
UPS	Uninterruptible Power Supply
V	Volt
VOC	Volatile Organic Compound
W	West
WA	Washington State
WAC	Washington State Administrative Code
WISHA	Washington Industrial Safety and Health Administration
WSDOE	Washington State Department of Ecology
WSDOT	Washington State Department of Transportation
yd³	Cubic yard

1. COGENERATION PROJECT SITE DESCRIPTION

The Cogeneration Project would be a combined cycle cogeneration (steam and electricity) facility located at the BP Cherry Point Refinery (Refinery), which is 6 miles northwest of Ferndale, 7 miles southeast of Blaine and about 15 miles north of Bellingham in northwestern Whatcom County, Washington. The nearest community is Birch Bay, located about 2 miles northwest of the site. The Canadian border is about 8 miles directly north of the proposed site. The Cogeneration Project would be sited adjacent to the northeast corner of the Refinery. The location of the proposed Cogeneration Project is shown on Figure 1.0-1.

The entire project, including the generation plant and support facilities, the new transmission line, natural gas and water supply lines, and construction laydown areas would be on BP Refinery-owned property. Details of the Cogeneration Project are provided in drawing AD-00-4300-00108. This area is within the Cherry Point Major Industrial Urban Growth Area/Port Industrial Zone as defined in the Whatcom County Comprehensive Plan, issued May 20, 1997. The entire project area is zoned Heavy Impact Industrial. The Cogeneration Project site would occupy 33.17 acres of unimproved land. The location of land owned by BP and the location of the project site is shown on Figure 1.0-1. The legal description of the Cogeneration Project site is given as follows:

A portion of the Northwest Quarter of Section 8, Township 39 North, Range 1 East, W.M., Whatcom County, Washington; more particularly described as follows:

Commencing at the monument marking the Northwest corner of Section 8, Township 39 North, Range 1 East; Thence S 16-48-33 W, 1428.01 Feet to the brass monument at the intersection of First Street and F Street, within the BP Cherry Point Refinery, said point having coordinates North 13925.00 Feet and East 9430.00 Feet; Thence North, 35.00 Feet; Thence East, 769.71 Feet to a chain link fence and the Point of Beginning, said point having coordinates North 13960.00 Feet, and East 10199.71 Feet; Thence N 00-01-08 W along said fence, 1229.74 Feet to a line parallel to and 15 Feet Southerly of the Arco Western Gas Pipeline ; Thence N 88-54-10 E, along said line, 1164.91 Feet; Thence South, 1252.05 Feet; Thence West, 1164.29 Feet to the Point of Beginning.

Containing 33.17 acres, more or less.

The basis of bearings and coordinates for this description is Cherry Point Refinery Plant Datum. The bearing of the West line of the Northwest quarter of said Section 8 is N 2-50-59 W.

The land surrounding the proposed Cogeneration Project is relatively flat and owned by BP for at least 0.5 miles in all directions. The closest residence is about 0.75 miles north and east of the proposed Cogeneration Project.

Prior to Refinery construction in 1969 the Cogeneration Project site and surrounding land was used for agriculture. Today the vegetation in that area consists mainly of grasses with areas of hybrid popular trees that were planted by BP for harvesting. The only relatively mature forests in the area are small patches that developed from

abandoned homesteads. Land north of Grandview Road and north of the proposed Cogeneration Project is owned and used by BP for habitat enhancement and buffering industrial operations. Terrell Creek is located within BP's habitat enhancement area and is about 0.5 miles north of the Cogeneration Project. Industries in the area other than the Refinery include the Chemco plant located about 0.75 miles east of the project site and the Praxair plant located 0.75 miles south of the project site.

The infrastructure necessary to support the Cogeneration Project is completely contained within or immediately adjacent to BP-owned land (Figure 1.0-2). Water for the Cogeneration Project would be provided ~~by from the Refinery system, which is supplied from~~ the Whatcom PUD water supply system. The Whatcom PUD source of water to the ~~Refinery Cogeneration Project will be the recycled cooling water from the Alcoa aluminum smelter is obtained from the Nooksack River. A The~~ water supply connection ~~from the Refinery~~ to the Cogeneration Project would be located on BP-owned land.

The electrical transmission corridor from the Cogeneration Project would be on BP-owned land. This transmission line would connect the Cogeneration Project to the BPA transmission line adjacent to BP property. The electrical transmission line corridor for Cogeneration Project, connections to the BPA electrical transmission system and the Refinery are shown in Figure 1.0-2.

Natural gas supply to the Cogeneration Project would be from the existing 16-inch diameter Ferndale Natural Gas Pipeline as shown in Figure 1.0-2. If supplemental natural gas is needed, it would be supplied from a third party pipeline, the connection to which would be located adjacent to the Cogeneration Project site near the Ferndale pipeline.

Details of the electrical transmission lines and natural gas pipeline locations and connections are provided in drawings AD-00-4300-00108, AD-00-4300-00109, and SK-BE7737-MD-0005, attached as exhibits to this appendix.

The proposed Cogeneration Project is consistent with existing land uses in the surrounding area. The BP Refinery and surrounding properties owned by BP are zoned Heavy Impact Industrial and Light Industrial. The Cherry Point Major Industrial Urban Growth Area/Port Industrial Zone totals approximately 6,500 acres, of which approximately 2,500 acres are occupied by heavy impact industries (Whatcom County Comprehensive Plan, 1997). Land use maps of western Whatcom County and of the Cherry Point subarea from the Comprehensive Plan are presented in Figures 1.0-3 and 1.0-4, respectively.

The Cogeneration Project site would be located to provide a 337-foot buffer from the ~~north fence line of the~~ site to the centerline of Grandview Road. This buffer would be used for landscaping to mitigate visual impacts of the Project from travelers on Grandview Road.

2. ON-SITE FACILITIES

2.1 Design Basis

The design basis for the Cogeneration Project provides a high-efficiency combined-cycle natural gas-fired cogeneration plant. Because the Project would also generate steam for the Refinery, sufficient equipment redundancy is essential. The Project design basis includes features that minimize impacts on the environment and on natural resources. The Cogeneration Project will be designed and constructed in strict conformance to applicable Federal, State, local and industry building codes and standards for thermal power plants as identified in Attachment A of this report. These Codes and Standards account for climatic conditions and natural hazards that exist for the specific site. A full Start-Up and Commissioning Program will transition the Cogeneration Project from the construction phase to commercial operation and will involve:

- Owner operator training,
- System scope definition,
- Systems cleaning and flushing,
- Loop and circuit checks,
- Calibration checks,
- System documentation and development of as-builts,
- System turnover,
- Trial runs,
- Electrical system and transmission testing
- Operational testing, and
- Performance and reliability testing.

2.2 Plant Site Arrangement

The proposed Cogeneration plant layout is presented in Figure 2.2-1. A three-dimensional view of the plant from Grandview Road is provided in Figure 2.2-2.

Major ~~structures/buildings~~ for the Cogeneration Project include the Steam Turbine Generator (STG) ~~enclosure/Building~~, Administration, ~~Control and Warehouse/Maintenance~~ Building, ~~Control Room~~, Water Treatment Building, ~~Maintenance Shop, Warehouse, and three Switchyard Control and Switchgear~~ Building (75' by 90').

The STG ~~Building/enclosure~~ would be approximately ~~150~~190' by ~~110~~90' by ~~105~~50' tall and would house the STG, the condenser pumps and other equipment associated with the operation of the STG. The STG transformers ~~and ACC~~ would be located outside the STG ~~enclosure/Building~~. The STG ~~enclosure/Building~~ would likely consist of three floors: a ground floor, mezzanine level, and the steam turbine operation floor. ~~The STG building would have an overhead crane for maintenance of the STG. The STG would have a weather enclosure and would be serviced using a gantry crane.~~ The STG itself would be supported on a reinforced concrete "Table Top" structure within the STG ~~enclosure Building~~.

The Administration, Control and Warehouse/Maintenance Building (approximately 220' by 60') (~~120' by 70'~~), Control Building (-80' by 50'), and Warehouse/Maintenance Building (-160' by 70') would be single-story metal buildings built on concrete slabs at grade. The Administration building portion would provide facilities for plant administration and general support functions. The Control Building portion would provide space for the plant's main controls, emergency batteries for uninterruptible power supply (UPS), and electrical support equipment. The Warehouse/Maintenance Building portion would provide for warehousing and general plant maintenance facilities.

A small control laboratory room would be provided in the Water Treatment Building (approximately 150' x 90'). In addition, several small-prefabricated buildings such as power distribution centers, switchyard control houses, and a guard shack would be also included.

The major buildings would be constructed of metal and pre-engineered per building manufacturer's standards. These would be steel-framed structures with roof trusses. The roofing and siding would be metal panels with standard insulation to withstand local weather conditions. The design and construction of these buildings and other structures would be in accordance with the appropriate codes and standards.

Major outdoor equipment ~~not contained within building~~ includes the Air-Cooled Condenser (ACC), the Cooling Tower, the Heat Recovery Steam Generators (HRSGs), Combustion Gas Turbine Generators (CGTs), electrical grid in the switchyard, transformers and the stack. The ACC Cooling Tower would be approximately 335' 110' by 225' 330' by 115' 60' tall and be used for condensing steam removing heat by from the steam turbines circulating water to the condenser downstream of the steam turbine. Each of the three HRSGs would be approximately 150' 110' by 45' 30' by 85' 95' tall, and would each have a 150' tall stack. A view of the Cogeneration Project looking south and east is provided in drawing AD-00-4300-00110 provided as an exhibit to this appendix.

2.3 Project Configuration

The Cogeneration Project would produce a nominal 720 megawatts (MW) and export electricity and steam to the Refinery, as schematically illustrated in Figure 2.3-1. The Cogeneration Project would be configured with three natural gas fired CGTs. Each CGT would be equipped with a heat recovery steam generator (HRSG) with supplemental duct-firing capability ~~and integral deaerators~~. Steam produced from the three HRSGs would be sent to a single steam turbine electric generator (STG) with process extraction and ACC condensing capability. The performance of the Cogeneration Project is summarized in Table 2.3-1 for various ambient temperatures and operating loads. The heat and materials balance for the base load case (50° F ambient temperature at 65 44 % relative humidity with out duct firing and is presented in Table 2.3-2).

The Cogeneration Project integrates its operation with the Refinery to increase efficiency and reduce the consumption of and impacts to natural resources. Figure 2.3-2 illustrates this integration. The Cogeneration Project would supply steam and electricity to the Refinery, which would in turn recycle condensate back to the Cogeneration Project. This steam supply would allow the Refinery to shut down older, less efficient boilers thus reducing emissions to the atmosphere and providing offsets to the atmospheric emissions from the Cogeneration Project. Table 2.3-3 compares the expected emissions

from the Cogeneration Project to the expected emission reductions at the Refinery and Table 2.3-4 identifies the boilers and equipment that will be shut down or modified to provide reductions ~~in criteria pollutant emissions from the Refinery for the criteria pollutants from the Cogeneration Project~~. The proposed Cogeneration Project would not use backup fuels, ~~although an emergency generator and fire water pump would be powered by diesel fuel~~. The Cogeneration Project would minimize fresh water consumption by ~~using an ACC or by~~ recycling industrial ~~waste~~ water instead of using fresh water cooling systems. The ~~small amount of~~ wastewater produced by the Cogeneration Project would be sent to the Refinery wastewater treatment system.

The Facility would generate a nominal 720 MW of electric power and export ~~high-pressure~~ process steam ~~and intermediate-pressure steam~~ to the Refinery. The Refinery would return ~~hot condensate and return boiler feed water (RBFW)~~ to the Cogeneration Project. The 635 MW of power generated in excess of refinery consumption would be exported via a new transmission line connected to the 230 kV BPA transmission line adjacent to BP property.

The Ferndale Pipeline would provide natural gas to the Cogeneration Project. High-pressure natural gas would flow through preheaters to improve efficiency and filter/separators before being combusted in the gas turbines. Low-pressure natural gas would be used for supplementary firing in the HRSGs.

The HRSGs generate steam from the hot exhaust of the CGTs. Each HRSG is equipped with supplemental duct firing to increase steam generation. The exhaust from the steam turbine would discharge into ~~an exhaust duct that leads to a multi-cell ACC~~ a ~~surface condenser~~ for the steam cycle heat rejection. The condensed steam ~~would be collected in the condenser hotwell from the ACC cooling coils would drain into the ACC hotwell tank~~. Condensate from the ~~ACC hotwell tank~~ would be combined with ~~RBFW condensate~~ from the Refinery before flowing back to the HRSG.

The major components and systems of the proposed project include:

- Three natural gas-fired Combustion Turbine Generators;
- Three Heat Recovery Steam Generators with supplemental duct firing capability;
- One Steam Turbine Generator;
- ~~One Air-Cooled Condenser; Cooling Tower;~~
- Steam, Condensate and Boiler Feedwater Systems;
- Heat Rejection System;
- Raw Water Makeup System;
- Demineralized Water System;
- Wastewater Disposal System;
- Natural Gas ~~and Refinery Gas~~ System;
- Compressed Air System;
- Fire Protection System;
- Plant Control System; and,

- Electrical Switchyard and Transmission Lines.

2.4 Combustion Turbine Generators

Table 2.3-1 provides the Cogeneration Project performance summary. Data provided throughout this description represent the best information currently available for the project's performance characteristics.

Thermal energy produced through the combustion of natural gas would be converted into mechanical energy in each CGT to drive an electric generator. The CGTs may be supplied by GE Power Systems, and would be located outdoors in suitable enclosures provided by the manufacturer.

Each CGT would consist of a heavy duty, single shaft, combustion turbine generator, and associated auxiliary equipment. The CGTs would be equipped with Dry Low NOx combustors for control of nitrogen oxides emissions. Each CGT would meet the following functional requirements:

- Air emissions at the gas turbine exhaust would not exceed the levels described in this application.
- Noise emissions would not exceed the near field and property line levels described in this application.
- Each CGT would be capable of operation down to 60% load while meeting required air emission performance.

The nameplate rating for each CGT generator would be 205 MVA at 18 kV and 0.85 power factor (pf). The CGTs would be equipped with the following accessories required to provide efficient, safe, and reliable operation:

- Inlet air filters and on-line filter cleaning system;
- On-line and off-line compressor wash system;
- Metal acoustical enclosures for noise attenuation;
- Fire detection and protection system;
- Lubrication oil system including oil coolers and filters;
- Hydrogen Cooled Electric Generator;
- Generator [hydrogen](#) coolers; and,
- Starting system, auxiliary power system, and control system.

The metal acoustical enclosures would contain the CGTs and accessory equipment.

2.5 Heat Recovery Steam Generators

The HRSGs would provide for the transfer of heat from the CGT exhaust gases to condensate and boiler feed water to produce steam. The HRSGs would be [a triple pressure reheat designs](#), generating superheated high-pressure, intermediate-pressure, and low-pressure steam for input to the steam turbine. Superheated high-pressure steam would be generated to provide throttle steam for the steam turbine. [and high-pressure export process steam would normally be extracted from the steam turbine, conditioned and exported](#) to the Refinery. Intermediate-pressure and low-pressure

steam produced from the HRSGs would flow to the STG. Each HRSG would be equipped with duct burners for supplementary firing with natural gas. The selective catalytic reduction (SCR) system complete with anhydrous ammonia storage, transfer, vaporization, and injection subsystems and CO oxidation catalyst would provide the secondary emission controls to meet the NO_x and CO emission targets. The duct burners and the HRSG are designed to maintain the steam turbine power production constant with changes in export steam demand, provide the nominal high pressure and intermediate pressure process steam demand of the refinery with only one gas turbine-HRSG train.

Pressure components of each HRSG would include a low temperature economizer, low-pressure evaporator, low-pressure ~~integral deaerator/storage~~ drum, low-pressure superheater, intermediate-pressure economizer, intermediate-pressure evaporator, ~~intermediate-pressure drum~~, intermediate-pressure superheater, intermediate pressure reheat superheater, high-pressure economizers, high-pressure evaporator, high-pressure drum and high-pressure superheaters.

Duct burners would be installed in the HRSG transition duct between the ~~high~~intermediate-pressure superheater and high-pressure ~~evaporators~~superheater. Through the combustion of natural gas ~~or on occasion supplemental refinery gas~~, the duct burners would reheat the CGT exhaust gases to generate ~~high pressure~~ steam at times when additional electricity and ~~/or~~ process steam would be needed. ~~The duct burners would also be used as needed to control the temperature of steam produced by the HRSGs.~~

Each HRSG would be equipped with a SCR system and catalytic oxidation to reduce emissions in the HRSG exhaust gas prior to discharge through the stack. The SCR uses anhydrous ammonia in conjunction with a catalyst bed to reduce oxides of nitrogen (NO_x) in the exhaust gases. The catalyst bed would be contained in a catalyst chamber located within each HRSG. Ammonia would be injected upstream of the catalyst bed. The subsequent catalytic reaction would convert NO_x to nitrogen and water, resulting in a reduced concentration of NO_x in the exhaust gases exiting the stack. CO oxidation catalyst located within each HRSG would reduce the concentration of carbon monoxide (CO) in the exhaust gases exiting the stack. The oxidation catalyst also would reduce the concentration of volatile organic compound (VOC) emissions.

2.6 Steam Turbine Generator

The STG system would include an extraction/induction/condensing ~~non~~-reheat steam turbine generator, governor system, steam admission and extraction systems, gland steam system, and lubricating oil system including oil coolers and filters, and generator coolers. The STG would be located in ~~an enclosure~~the steam turbine building. The STG would have a nameplate rating of ~~252~~ 243 MW at a throttle steam flow rate of ~~1.625~~ 1.314 ~~Kpph MM lb/hr~~ at ~~2030~~ 1900 psia and ~~1044~~ 1049° F. The amount of output will vary and is dependent on the number and loading of CGTs operating, the amount of steam going to the Refinery and the amount of duct firing occurring. Under the plant 100 % base design conditions, the STG has a gross power output of approximately ~~214~~ 223 MW. The 100% base load conditions include all three CGTs running, ~~3375~~ 510 kpph (thousands of pounds per hour) ~~HP steam and 449 kpph of 600-650 psig-psia IP steam~~process steam to the Refinery. The nameplate rating for the STG generator would be ~~300~~ 270 MVA, 18 kV and 0.9pf.

Steam from the high-pressure superheater, intermediate-pressure superheater, and low-pressure superheater sections of the HRSG would enter the corresponding sections of the STG where it would expand and drive the steam turbine and its generator. Upon exiting the turbine, the steam would enter the condenser where it would be condensed to water. A steam extraction port located on the STG would normally be used to supply intermediate pressure process/export process steam at 650 psig-psia and 750°F to the Refinery. The high pressure steam turbine would be equipped with a steam stop valve and steam control valve. In addition, the steam system includes steam conditioning stations to allow throttle steam to be conditioned to the process conditions of 650 psia and 750 deg F and discharged into the process steam line. Using throttle steam to provide process steam will be used when the steam turbine is out of service and to supplement process steam when demand is greater than 510 kpph.

The STG would be complete with the following components.

- Turning Gear,
- Exhaust Hood Spray,
- Stop Valve and Control Valve,
- Gland Seal Sealing and Condenser System,
- Generator with Control Panel,
- Vacuum Breaker,
- Gland Steam Seal and Condenser System,
- Hydraulic and Lube Oil System, and
- Electric Generator.

2.7 Electric Generator Transformers

Electric generators are integral components of the CGTs and STG. Each CGT generator would have a step-up transformer with a maximum continuous rating for would be 210 185 MVA. The maximum transformer rating for the STG generator would be 300 275 MVA.

2.8 Steam and Condensate System

2.8.1 System within Proposed Plant

The steam system is shown on drawings AD-00-4300-0011100100, AD-00-4300-00101, and AD-00-4300-00104 that are attached as an exhibits to this appendix. In the HRSG, superheated high-pressure steam would be generated to provide throttle steam for the steam turbine and high pressure export process steam to the Refinery. A steam extraction port located on the STG would be used to normally supply process steam at 650 psia and 750°F to the Refinery. Intermediate-pressure and low-pressure steam produced from the HRSGs would flow to the STG. HRSG makeup water would be preheated in the low temperature economizer before entering the low-pressure boiler. A single recirculation pump would maintain the makeup water inlet temperature above the water dew point of the exhaust gas.

High-pressure, intermediate-pressure, and low-pressure steam from the HRSG would flow to the ~~non~~-reheat, extraction, admission, and condensing STG. ~~Intermediate-pressure p~~Process steam would be extracted from the steam turbine and conditioned prior to export to the refinery. Redundant high-pressure to ~~intermediateprocess~~-pressure letdown stations with desuperheaters would be included to maintain reliability of ~~intermediateprocess~~-pressure steam supply in the event of a steam turbine outage.

The exhaust from the steam turbine would discharge into an exhaust duct that leads to a ~~multi-cell ACC~~surface condenser for the steam cycle heat rejection. The condensed steam from the ~~ACC cooling coils~~condenser would ~~drain into the ACC be collected in the~~ hotwell ~~tank~~. ~~Vacuum condensate from the ACC hotwell tank would be pumped to RBFW and Hot Condensate Coolers before flowing back to the HRSG.~~

2.8.2 Integration with Refinery

The Cogeneration Project will supply the Refinery with ~~two types of steam. The first type is HP desuperheated process steam, identified on Table 2.3-2 stream no. "S13". This stream has a flow rate of 337 kpph at a temperature of 645° F and a pressure of 1870 PSIA. The second type is IP process steam, as identified on Table 2.3-2, as stream no. "S14". This steam has a design flow rate of 449770 kpph at a temperature of 750° F and a pressure of 650 PSIA.~~

The Cogeneration Project will receive ~~condensate two streams~~ from the refinery ~~containing condensate. The first of these streams is hot condensate, identified on Table 2.3-2 as stream no. "W10". This is the condensate from the HP desuperheated process steam used to preheat crude, and it has a design flow rate of 321 kpph. The second stream containing condensate is or hot BFW, as identified on Table 2.3-2 as stream no. "W11". This stream is actually a mix of demineralized treated raw water and condensate that comes off the refinery's existing BFW system. This stream has a design flow rate of 201700 kpph. The percentage of water returned from the refinery would be calculated by dividing the sum of these two streams by the sum of the two steam streams sent to the refinery (W10 + W11)/(S13 + S14)*100 or (321 + 201)/(337 + 449)*100 or approximately 66%. 90% of the process steam flow.~~

2.9 Electrical Interconnection

Power to the Refinery is currently delivered from three 115-12.5 kV substations owned by Puget Sound Energy (PSE) and located on the east side of the Refinery. The 12.5kV output of these substations is connected to three Refinery-owned substations (MS-1, MS-2 and MS-3) for distribution to Refinery electrical loads.

The proposed 230 kV switchyard for the Cogeneration Project is illustrated in drawing PD-00-4300-101, attached as an exhibit to this appendix. The equipment required for this switchyard would consist of ~~15~~ 230 kV breakers and associated controls arranged in a "breaker and a half" configuration, two outgoing circuits to the BPA transmission grid, and three 150 MVA 230-69 kV transformers with overhead lines or cables to the proposed intermediate voltage Refinery 69 kV substation. While this intermediate voltage may be 69 kV or 115 kV, the intermediate voltage substation and its components are referred to as "69 kV" substation in this document and other sections. The voltage of this system will be determined during the project detailed design phase.

The configuration of the new Refinery 69 kV substation is shown on drawing PD-00-4300-103 attached as an exhibit to this appendix. The three Refinery-owned substations would be disconnected from PSE and reconnected to this new substation. This substation would consist of ~~14 gas-insulated~~ circuit breakers with six 60 MVA 69-12.47 kV feeder transformers (two each at MS-1, 2 and 3), two new outdoor walk-in type 12.47 kV switchgear (one each at MS-1 and 2), interconnecting 69 kV overhead lines or cables between the switchyard and the transformers, and non-segregated buses at MS-1 and MS-2.

A double circuit 0.8 mile long transmission line from the 230 kV switchyard to the interconnection point at Kickerville Road with the BPA transmission corridor would export power from the Cogeneration Project. The proposed electrical transmission corridor to the BPA transmission system is shown on drawings AD-00-4300-00108 and AD-00-4300-00109, which are also attached as exhibits to this appendix.

Ownership of the new 230kV switchyard, and new electrical transmission towers and lines connecting this switchyard to the existing BPA transmission lines would be subject to the terms of the interconnection agreement with BPA. The Refinery would retain ownership of the land for the switchyard and transmission line corridor.

A description of this transmission line and proposed interconnection to the 230 kV BPA transmission lines is provided in Section 3 of this Technical Report.

2.10 Noise

The design of the proposed Cogeneration Project incorporates many noise mitigation measures. Noise was considered in the siting and orientation of noise-producing equipment. Engineering controls are also proposed to reduce sound levels. The main plant components that generate noise would be the steam turbine, the gas combustion turbines, the HRSGs and stacks, ~~and the ACC and the cooling tower.~~

Existing noise levels were monitored and incremental noise increases from the Cogeneration Project were modeled at 15 receptor locations in the surrounding area. Additional more extensive background monitoring was performed at the four nearest residential receptors and modeling was updated based on the revised project design. The results of the ~~modeling analysis~~ indicate the predicted noise from the Cogeneration Project will be well below state regulatory requirements and will not effect have any tangible effect on the nearest residential receptors. not create a perceivable difference to background sound levels at receptor locations outside BP owned property. The modeled results are very conservative because they do not account for sound attenuation from the surrounding environment (vegetation, topography, and terrain) and engineering controls (mufflers, housing and sound transmission blockage by existing and planned structures). The details of the noise study and modeling results are provided in Part III Appendix K.

2.11 Access Roads

Three permanent roads would be constructed to provide for access to the Cogeneration Project. These roads would permit access from Grandview Road on the north, Brown

Road on the south (actually a short extension of the transmission corridor access road), and Blaine Road on the west. The three access roads are proposed to provide flexibility for access during emergency situations.

A permanent plant road would be constructed around the site perimeter with branch roads providing access to specific plant areas such as the CGTs, STG, HRSGs, Water Treatment, ~~Control Administration Building, Warehouse, and air-cooled Condensers and cooling tower.~~

Passenger vehicle parking would be provided at the Administration, ~~Building,~~ Control ~~Building,~~ and Warehouse/Maintenance Building. All roadwork within the plant would be constructed to facilitate plant access and maintenance in accordance with AASHTO standards; roadwork outside the plant boundary would be ~~performed~~constructed in accordance with the Washington State Department of Transportation (WSDOT) and emergency vehicle requirements. The permanent and temporary access roads for the Cogeneration Project are shown on drawing AD-00-4300-00108, which is attached as an exhibit to this appendix.

2.12 Ancillary Systems

2.12.1 Auxiliary Cooling

A closed cooling water system (CCWS) would be provided for auxiliary cooling in the facility. The system would include ~~air-cooled fin fan coils~~cooling water to glycol heat exchangers, 2-100% CCWS pumps, a thermal expansion tank, and distribution piping system. The cooling water would be a mixture of approximately 45% ~~poly~~propylene glycol and 55% demineralized water. ~~The demineralized water system would provide makeup water directly to the expansion tank, and a chemical pot feeder would be utilized for future additions of glycol. This system would be designed to deliver a maximum 105°F cooling water during an 85°F dry bulb ambient summer day.~~

2.12.2 Overall Plant Control System

The control system would consist of a Distributed Control System (DCS) using microprocessor-based controllers, redundant communications network, and an Operator Console.

The DCS control system would provide continuous control, monitoring, alarming and trending for the entire plant. The DCS hardware would be based on a distributed architecture consisting of input/output modules, controllers, communication networks and man-machine interface. The ~~DCS~~ controllers would provide all regulatory control and monitoring functions for the plant. The controllers would be redundant and provide automatic, smooth transfer to back-up in the event of a malfunction.

The DCS control system would be capable of providing sequence of events functions as part of the ~~DCS hardware~~. Time stamping and printing of information would be via the DCS included hardware. A separate alarm printer would log all points that are in an alarm condition and document all operator-initiated changes.

The [DCS control system](#) would be powered through an uninterruptible power supply to maintain power to the [DCS control system](#) from batteries in the event of a power failure.

2.12.3 CGT, STG Control Equipment

The gas and steam turbines would be controlled by equipment provided by the CGT and STG suppliers. Primary operator interface would be from the respective CRTs located on the operator console. From these CRTs, the operator would perform all start-up, control, and monitoring functions. Control of critical loops from the DCS would be via hardwired signals to and from gas turbine controllers.

The plant DCS would control the HRSGs. All control and monitoring functions would be hardwired to the DCS racks.

The balance of plant would be controlled by the DCS to control the steam distribution, fuel handling, boiler feedwater, [cooling water, ACC and](#) condensate, instrument air, chemical injection system, closed cooling system, and water treatment systems. The primary control of the water treatment system for sequencing resin beds regeneration and neutralization of regeneration wastes would be performed by the water treatment equipment supplier's control equipment which would be linked to the DCS via data highway.

2.12.4 Emissions Monitoring System

A Continuous Emissions Monitoring System (CEMS) would be included to monitor HRSG stack emissions continuously. The analysis of nitrogen oxides (NO_x), carbon monoxide (CO), ammonia (NH₃) and oxygen (O₂) of each HRSG stack would be transmitted to the Data Acquisition System (DAS) in the control room. The DAS would perform the necessary calculations and provide the reports as stipulated by the Air Permit. Data collected by the DAS required to perform these calculations would be provided via hardwired link. NH₃ would be monitored to maintain control of the ammonia slip. Emissions of sulfur oxides (SO_x) would be estimated from the sulfur content of the fuel.

2.12.5 Plant Electrical System

The Cogeneration Project electrical system would include CGT and STG step-up transformers, isolated phase bus ducts between generators and transformers, gas turbine generator breakers for auxiliary load distribution system, 100% capacity plant auxiliary load transformers, 4160 and 480V distribution system for plant auxiliary loads, motor control centers, plant lighting, UPS with battery backup, and electric tracing for freeze protection.

The power block start-up power would be back-fed from the 230 kV switchyard using either one of two auxiliary load transformers.

2.12.5.1 Generator Step-Up Transformers

Each CGT step-up transformer would have a maximum rating of 210 MVA and a nameplate rating of 205 MVA at 18 kV and 0.85 pf. The STG step-up transformer would be rated for 300MVA at 18kV and 0.9 pf.

2.12.5.2 Generator Metering and Control Panels

The CGT equipment supplier would provide a Packaged Electronic and Electrical Control Compartment (PEECC) for each CGT to house the turbine protection, metering, control, and synchronizing systems. The steam turbine protection, metering and controls, and synchronizing would be provided by the STG supplier and are located on panels in the substation building adjacent to the control room.

2.12.5.3 Plant Auxiliary Load Transformers

Two 18kV to 4160 V three-winding transformers rated at 40 MVA would supply power to the plant auxiliary loads. Additional 4160 V to 480 V power distribution transformers would be included as part of the power distribution system.

2.12.5.4 4160 Volt System

The 4160 V switchgear would be located in the 4160 V power distribution center and provide power to all 4160 V motors, the CGT excitation and starting transformers and the plant 4160 V to 480 V transformers.

2.12.5.5 480 Volt System

The 480 V switchgear would provide power to CGT motor control centers (MCCs), the common auxiliary MCC, and water treatment system MCCs. Each CGT would have an MCC furnished by the equipment supplier and located in the respective PEECC. Auxiliary and water treatment MCCs would be in 480 V power distribution centers located in close proximity to their loads.

2.12.5.6 UPS and 125 V Backup Power Systems

The UPS would provide normal and backup power to the DCS and other critical instrumentation and power supply loads. The UPS would normally be fed from a 480 V MCC but would also be connected to a 125Vdc battery system for backup power. The CGT supplier would furnish a 125Vdc battery backup power supply with charging system for each CGT control system. The station battery would supply dc power to the DCS and other critical plant equipment. The station batteries and chargers would be located in the auxiliary substation.

A small diesel-powered emergency generator would also be provided to maintain critical lubrication system operation in the event of a total grid power failure. This generator is not expected to be larger than 1500 kW.

2.12.6 Site Security

An 8-foot tall chain link security fence topped with barbed wire would surround the power plant. Automatically or manually operated gates would be provided at all roads crossing the fence and lockable personnel gates would be added where appropriate. The electrical switchyard would have its own perimeter fence and gates of similar construction to prevent unauthorized access to the high voltage equipment. More details are provided in Appendix J: Technical Report on Emergency and Security Plans.

2.12.7 Fire Protection

Fire protection systems would be provided to limit personnel injury, property loss, and plant downtime resulting from a fire. The fire protection system would consist of a site perimeter firewater loop with post indicating valves and hydrants, an automatic deluge system for transformers, a sprinkler system for steam turbine lube oil equipment and bearings, and detection and alarm equipment. A carbon dioxide system, provided by the CGT supplier, would protect this equipment. Buildings would have fire protection as follows: Pre-action system for Administration Building ~~and Auxiliary Substation Building, automatic gas suppression system for the Control Room~~ and dry stand pipe and Class III hose stations for all other buildings. Portable fire extinguishers of appropriate sizes and types would be located throughout the power plant site. More details are provided in Appendix J: Technical Report on Emergency and Security Plans.

A diesel-driven firewater pump would be provided to ensure adequate firewater pressure for the Cogeneration project under a power failure or low water supply pressure scenario. This firewater pump is expected to be approximately 265 hp in size.

3. ELECTRICAL TRANSMISSION SYSTEMS

3.1 Transmission Corridor and Towers

The Cogeneration Project would be connected to BPA's Custer substation for transmission of power not used by the Refinery. Two lines would be used to connect the Cogeneration Project to the BPA transmission system. The ownership of these facilities would be subject to the terms of the interconnection agreement with BPA.

Two 230 kV transmission lines connect BPA's Custer substation to BPA's Intalco substation at the Alcoa Intalco works aluminum smelter. These transmission lines are routed in two separate corridors with 'H' pole configurations supporting one transmission circuit each. Near the Refinery these corridors both run in a north-south direction. The western transmission line corridor runs adjacent to Kickerville Road about 0.8 miles to the east of the Cogeneration Project site. This location is the most convenient place to interconnect the Cogeneration Project to the BPA system using the existing transmission lines.

Transmission Line Single Contingency Analysis

BPA performed single contingency analysis for the Cogeneration project and Refinery load along with the potential Alcoa load on their two existing 230 kV transmission lines. This analysis determines whether each line by itself can carry all combinations of loads and generation possible in this system should the other transmission line fail.

This analysis showed that under certain combinations of electrical loads, and when certain sections of transmission line are lost, one or more portions of the remaining line could exceed its thermal operating limit of 100 degrees Celsius. Whether or not this occurs depends upon the ambient temperature at the time of the line loss.

At or below about 68F the remaining line always has sufficient capacity; above 68F the line begins to exceed its temperature limit. This effect increases as ambient temperature increases. At 95F (the maximum expected ambient temperature) and the worst contingency case the overload would be about 40 MW, or 7% of the allowable line capacity.

While this combination of events is very unlikely, it must be provided for in the system design. There are three options to remedy this situation:

- 1) Install a remedial action scheme to reduce load or generation on the 230 kV system when the combination of events described above occurs. This option would require no changes to the 230 kV lines or towers, but would require the agreement of the Refinery, Alcoa and the Cogeneration Project.
- 2) Install a second transmission line inside the existing westernmost 230 kV line corridor leading from the Refinery to the Custer substation to "double up" the existing transmission line along this segment. The existing transmission towers in this roughly 4-mile long segment are not strong enough to carry a second circuit so the existing towers would be replaced with new stronger monopole or lattice towers. The towers would likely be replaced one-at-a-time by temporarily supporting the existing wires while each tower was replaced. Some foundation

work would likely be required to accommodate the new towers; therefore some impact to land within the existing right-of-way is anticipated for this option. BPA would also be required to add two breakers to the Custer substation ring buss to accommodate this new line. Under this option, no remedial action scheme would be required to reduce load or generation should any single contingency occur.

- 3) Replace the existing 230 kV transmission lines with higher capacity lines. This option may require upgraded or new towers if a wire type is not found which provides the required capacity with the same weight as the existing wire. If a wire type can be found with similar weight and sufficient capacity certain tower modifications may still be required. Under this option, no local remedial action scheme would be required. At the time of this ASC amendment, several wires have been evaluated but a suitable wire type has not been found.

BP strongly prefers the remedial action scheme because it would not require changes to the existing transmission lines and towers.

230 kV Line Interconnection to the Cogeneration Project

The proposed electrical transmission corridor to the BPA transmission system is shown on drawings AD-00-4300-00108 and AD-00-4300-00109. The proposed Cogeneration Project would use two types of towers for the electrical transmission lines. A monopole would be used at the switchyard within the Cogeneration Project site. Within the electrical transmission corridor to the BPA system, lattice towers would be used. Figures 3.1-1 and 3.1-2 present conceptual drawing of the monopole and lattice towers, respectively. There would be four lattice towers numbered 1 through 4 with number 1 being close to Kickerville Road for the interconnection to the BPA system. Tower number 4 would be south of the Cogeneration Project and be connected to the monopole tower at the Cogeneration Project switchyard.

3.2 230 kV Switchyard Configuration

3.2.1 Intermediate “69 kV” Step Down Transformers

An open-air (air insulated) 230 kV switchyard configuration would be used at the Cogeneration Project. A layout of this switchyard is provided in drawing AD-00-4300-00108. Three 150MVA transformers located in the 230 kV switchyard would step down power from 230 kV to an intermediate voltage 69 kV to facilitate distribution within the Refinery. While this intermediate voltage may be 69 kV or 115 kV, the intermediate voltage substation and its components are referred to as “69 kV” substation in this document and other sections. The voltage of this system will be determined during the project detailed design phase.

3.2.2 Breaker Configuration

The 230 kV switchyard would utilize a “breaker and a half” configuration as shown in the one-line diagram drawing PD-00-4300-101. This configuration would allow for switchyard maintenance and would provide redundancy for both the power supply to the Refinery 69kV substation and the 230kV circuits that interconnect the Cogeneration Project to the BPA system.

3.3 69 kV Refinery Switchyard Configuration

The proposed Refinery 69 kV switchyard would distribute power to the existing Refinery substations (MS-1, 2 and 3) from the 230 kV switchyard (see drawing AD-00-4300-00108). This switchyard ~~would~~ may feature an indoor gas-insulated substation in a radial breaker arrangement. A total of nine connections would be required, three connections to the three transformers providing power from the 230 kV switchyard, and two connections each to the new distribution transformers in MS-1, 2, and 3. Electrical connection details are shown in the 69 kV one-line diagram drawing PD-00-4300-103.

4. FUEL SYSTEM

4.1 Fuel Used

This section describes the natural gas fuel system that would be required by the proposed project and the source and quality of the fuel. Natural gas would be used as the fuel source for the gas turbines and duct burners. The estimated fuel consumption at various operating conditions is provided in Table 2.3-1.

Natural gas is supplied to the Refinery via the Ferndale Pipeline, which takes natural gas from the Westcoast Pipeline system near Sumas, Washington at the U.S./Canadian border and transports it to the Refinery and to the Alcoa Intalco Works Smelter. Table 4.1-1 presents a typical natural gas analysis.

The Ferndale Pipeline would deliver gas to the Cogeneration Project site at a pressure of about 250-300 psig. The CGTs and some Refinery operations require a higher fuel pressure, so natural gas compressors (described below) would raise the pressure of this gas to approximately 500psig. The natural gas would be filtered prior to entering the CGT and duct burner systems. Each CGT natural gas system would use a gas preheater to increase the gas temperature for performance enhancement. The HRSG would provide intermediate-pressure feedwater for natural gas heating purposes.

Natural gas compression would not be required for gas that would be burned by the HRSG duct burners.

4.2 Natural Gas Connection and Compressor Facility

Installation of new electric-driven natural gas compressors would be required to provide sufficient fuel pressure for the CGT and some Refinery operations. The compressor facility would be constructed just west of the Cogeneration Project on BP property. Access to the compressors would be from Blaine Road. The compressor facility would feature a building to enclose the electric-driven compressors, and a gas detection and fire detection and extinguishing system.

Drawing AD-00-4300-00108 shows the location of the natural gas compressor facility and the existing Ferndale Pipeline Metering Station. Drawing SK-BE7737-MD-0005 shows the connection to the existing Ferndale pipeline, arrangement of the gas connections and fence line.

The connection to the Ferndale Pipeline would be installed between the existing metering station, routed underground under Blaine Road to the new compressor facility (Tie-In Point 17) on drawing SK-BE7737-MD-0005. Natural gas supply to the Alcoa Intalco works would be tied into the existing 8-inch diameter section of the Ferndale Pipeline at Tie-In Point 16. The connection from the compressor facility to the Refinery would be routed underground, under Blaine road back to the Tie-In Point 5 at the metering station. The connection from the compressor facility to the Cogeneration Project would be routed from the compressor facility along the new pipe rack above ground. The existing Ferndale line metering station piping would require some minor modifications to accommodate metering for the Cogeneration Project.

5. SYSTEM OF HEAT DISSIPATION

The Cogeneration Project STG steam cycle heat rejection system would feature ~~an air-cooled condenser (ACC), or possibly~~ a water cooled system using recycled industrial water from the nearby Alcoa aluminum smelter. ~~wastewater. The ACC and cooling options were selected. The use of ACC requires higher capital expenditures than water cooling systems and results in a lower electrical output. The use of recycled industrial wastewater for cooling would require the cooperation of third parties, and is not proposed as the primary option because the required agreements have not yet been made.~~

The ~~ACC~~ surface condenser would receive exhaust steam from the low-pressure section of the STG and condense it to liquid for return to the HRSGs. ~~The ACC would consist of multiple modules of finned tubes arranged in an "A" frame configuration with fans and electric motor drives. Figure 5.0-1 shows one "A" frame module with an electric fan. Each module would condense wet, saturated exhaust steam from the STG with ambient air.~~ The condenser would be designed to operate under full vacuum. Steam would ~~enter the header tubes from the peak of the "A" and would be cooled and be~~ condensed as it flows downward through the condenser tube bundle. ~~into a hotwell tank.~~ The condensate is collected in the hotwell and would then be pumped back into the steam cycle. ~~Fan design and placement would minimize noise emitted to the surroundings.~~ The steam and heat dissipation system within the Cogeneration Project is shown on drawing AD-00-4300-~~00111. 00101.~~

~~The ACC would use for cooling. The cooling tower makes use of evaporative cooling in removing heat from the circulating water after it passes through the surface condenser.~~ Condenser pressure would increase as ~~the ambient dry bulb~~ cooling water temperature increases. Steam turbine performance and efficiency would decline as the condenser pressure increases.

6. WATER SUPPLY SYSTEM

6.1 Construction Water

During construction, non-potable water would be supplied by truck or by connection to the Refinery non-potable water system to provide dust control and other construction uses. ~~to provide drinking water to construction workers. The~~ Potable water service would be contracted out ~~to a company~~ or supplied ~~per the site~~ by the EPC contractor.

6.2 Water For Cogeneration Project Operation

Water Sources

~~All water~~ Water supplied to the Cogeneration Project during operation would be provided from ~~the Refinery.~~ Whatcom County PUD and the Birch Bay Water and Sewer District. Two streams of fresh water would be required by the Cogeneration Project (see drawing AD-00-4300-001~~1207~~): (1) Potable and (2) Non-potable cooling tower and boiler make-up water. The potable water source to the Refinery is Birch Bay Water and Sewer District. The additional amount of potable water required for drinking, personal washing and sanitation use by the Cogeneration Project would be minimal, averaging about between 1 to 2-5 gpm. Potable water will be conveyed to the Cogeneration Project ~~from the Refinery~~ through underground piping on BP property. The anticipated route of the underground water pipeline connection is along the east-west access road from the Refinery to the Cogeneration Project.

The source of non-potable raw industrial water to the Refinery is Whatcom County PUD. The Refinery has a contract to purchase ~~industrial~~ this water from Whatcom County PUD from January 1, 2000 to December 31, 2030. ~~Whatcom PUD obtains this water from the Nooksack River under a certified Water Right. Whatcom PUD owns and operates an existing pipeline from the Nooksack River diversion to the Refinery. The point of delivery is at the existing meter in the southeast portion of the Refinery. The water is non-potable with an average turbidity of 10 NTU or less. The Refinery operates a supply water filtration system for the water received from the Whatcom County PUD. Fresh water would be delivered to the Cogeneration Project through an underground eight (8) inch diameter connection located within BP property. This pipeline connection would be routed along the east-west access road from the Refinery to the Cogeneration Project. Alcoa has a similar contract to purchase industrial water from Whatcom County PUD. Whatcom County PUD obtains water from the Nooksack River for both these contracts under a certified Water Right.~~

The Cogeneration Project would fund the installation of equipment that would allow industrial water currently used for non-contact once-through cooling at the Alcoa smelter to be returned to the PUD and reused by the Cogeneration Project and the Refinery. An average of 2,780 gpm of recycled industrial water would be available for use by the Cogeneration project and other industrial water customers of the Whatcom County PUD. The PUD would install a concrete sump or "wet well" estimated to be 10' by 40' by 10' deep on the south side of the Alcoa facility and cover it with steel plates or grating. Three 150 hp electric motor driven pumps located inside a shelter roughly 12' by 20' would also be provided, and would be tied into the PUD control system for monitoring and unattended operation. Once through non-contact cooling water from

the Alcoa air compressor building would drain to the wet well rather than being discharged to the Straight of Georgia. This water would be pumped from the wet well into the nearby PUD industrial water supply line via a new 16" pipe roughly 1,600 ft long. Valves would be provided in this pipe to prevent reverse flow and provide for isolation of the system. Normally only two pumps would be required to deliver the recycled water, so the third pump would serve as a spare.

The PUD would manage, install and operate the recycling equipment. Figure 6.2-1 shows schematically how the water recycle project would be incorporated into the industrial water supply system and shows its beneficial impact on Whatcom PUD industrial water use at average operating conditions.

Water Usage

Drawing AD-00-4300-00112 shows the disposition of water used by the Cogeneration unit. During typical operation, about 90% of the industrial water is used for the cooling tower, with the remainder used for boiler feedwater and for service water.

The annual average Cogeneration unit water usage summary is provided in Table 6.2-1. The Base and Worst Cases in this table depict average operation at 15 and 10 cycles of concentration respectively, at an average of 510 kpph steam demand by the Refinery. Cycles of concentration are typically maximized to conserve water and treatment chemicals, but may change if makeup water quality changes. On an annual average basis, the Cogeneration project saves 484 to 556 gpm water, resulting in a net decrease of water drawn from the Nooksack River for industrial use.

The Cogeneration project's water consumption would also vary with changes in the ambient temperature and the refinery steam demand. As the Refinery's steam demand is reduced, more duty is required of the cooling tower to condense steam produced in the HRSGs. Warmer ambient temperatures increase water use because of higher evaporation rates in the cooling tower.

Water Delivery Point

Whatcom County PUD owns and operates an existing pipeline from the Nooksack River diversion to both the Alcoa aluminum smelter and the Cherry Point Refinery. The industrial water point of delivery is at the existing meter in the southeast portion of the Refinery. An underground 16-inch diameter pipe would be installed from this delivery point to transport water to the Cogeneration Project. This pipeline would be routed along the east-west access road from the Refinery to the Cogeneration Project.

6.3 Raw Industrial Water Quality

Table 6.3-1 provides information from the Whatcom County PUD source water analysis for Cogeneration Project make-up water. The water is non-potable with an average turbidity of 10 NTU or less. The Refinery operates a supply water filtration system for the water received from the Whatcom County PUD. Fresh water would be delivered to the Cogeneration Project through an underground eight (8) inch diameter connection located within BP property. This pipeline connection would be routed along the east-west access road from the Refinery to the Cogeneration Project.

Since the Cogeneration Project would replace Refinery steam boilers, only 40 gpm of additional water on average would be required for the operation of both the Refinery and the Cogeneration Project. Currently, the Refinery uses an average of 4,170 gpm of water from the Whateom County PUD. With the proposed Cogeneration Project, an average of 4,210 gpm is expected to be required for the operation of both facilities. A summary of the water supply and the anticipated Cogeneration Project water consumption is presented on Figure 6.2-1 (water balance). Details of the water material balance are provided in Table 2.3-2.

6.3 Raw Industrial Water Quality

Table 6.3-1 provides information from the Whateom County PUD source water analysis for Cogeneration Project make-up water.

6.4 Raw Water Treatment Requirements and Methods

Drawing AD-00-4300-00112 provides a flow diagram of the water treatment system. Industrial water for the Cogeneration Project cooling tower requires no further treatment. However, water for the HRSGs must meet stringent specifications for suspended and dissolved solids. The recycled industrial water from the Whatcom County PUD does not meet the specifications required for steam generation. To meet these specifications, the water would be first filtered in two 100% media filters. Dissolved gases are removed in a forced draft decarbonator/deaerator. The filtered water would then flow to two demineralizers.

A polisher consisting of two 100% capacity mixed bed trains would be used to polish condensate and demineralized water returned from the Refinery.

Demineralized water from these systems would flow to Condensate Storage Tank and Demineralized Water Storage Tank, which would provide an uninterrupted supply of demineralized make-up water to the steam cycle, and would have 8 hours of boiler feedwater storage capacity should condensate return flow drop to zero. Water for the HRSGs must meet stringent specifications for suspended and dissolved solids. The raw industrial water from the Whateom County PUD does not meet the specifications required for steam generation. To meet these specifications, Refinery fresh water would be first filtered in three 50% media filters. The filtered water would flow to a roughing demineralizer consisting of three 50% capacity anion and cation bed trains. A polishing demineralizer consisting of three 50% capacity mixed bed trains would be used to polish cooled return boiler feed water (RBFW)/condensate and water from the roughing demineralizer. Demineralized water from the polisher would flow to the Demineralized Water Storage Tank, which would have a storage capacity of 24 hours. The tank would provide an uninterrupted supply of demineralized make-up water to the steam cycle. Drawings AD-004300-00105 and AD-00-4300-00106 are flow diagrams that illustrate the demineralization of the raw fresh water for the Cogeneration Project.

Additional conditioning of the condensate and feedwater circulating in the steam cycle would be provided by means of a chemical feed system. An oxygen scavenger for dissolved oxygen control ~~would be fed directly into the integral deaerator and~~ amine for pH controls would be fed into the condensate. To minimize scale formation, a solution

of alkaline phosphate would be fed into the feedwater of both the high-pressure and intermediate-pressure drums of the HRSG. The chemical feed system would include oxygen scavenger chemical containers, amine chemical containers, phosphate solution chemical containers for the high-pressure drum, and phosphate solution chemical containers for the intermediate-pressure drum. Each of the chemical containers would be provided with two full-capacity metering pumps, with the exception of the phosphate chemical feed system, which would have two full-capacity metering pumps, plus a common spare.

A steam cycle sampling and analysis system would monitor the water quality at various points in the plant's steam cycle. The water quality data would be used to guide adjustments in water treatment processes and to determine the need for other corrective operational or maintenance measures. Steam and water samples would be routed to a sample panel where steam samples would be condensed and the pressure and temperature of all samples would be reduced as necessary. The samples would then be directed to automatic analyzers for continuous monitoring of conductivity and pH. All monitored values would be indicated at the sample panel and critical values would be transmitted to the plant control room. Grab samples would be periodically obtained at the sample panel for chemical analyses that would provide information on a range of water quality parameters.

7. WASTEWATER TREATMENT AND DISPOSAL

7.1 Cogeneration Project Wastewater

During normal operation, the Cogeneration plant generates wastewater from the following activities:

- Treatment of raw water to produce high quality boiler feedwater (BFW), and treatment of returned Refinery condensate.
- Collection of water and/or other minor drainage from various types of equipment, and
- Sanitary waste collection, and from employee water use.
- Blowdown of water from the cooling tower.

The estimated flow and chemical composition of wastewaters from the Cogeneration Project are provided in Table 7.1-1, except for the sanitary wastewater stream.

All chemical feed areas will be provided with secondary containment curbs to capture spillage, tank overflows, and spills from maintenance operations and washdowns. Water from these areas would be transferred for treatment to the Refinery wastewater treatment system.

A wastewater stream is also generated periodically when a gas turbine is shut down in order to wash the compressor blades to restore peak operating efficiency. This is done several times per year per gas turbine depending on blade fouling severity. The operation generates approximately 2,2502,300 gallons of water containing airborne dirt that have been removed from the blades, along with lube oil residue and detergents used for the cleaning operation. The water is collected in a sump and either pumped or trucked to the Refinery waste water treatment system for proper disposal.

Even though the HRSGs utilize a very high quality BFW, a small portion must be blown down (purged) to remove trace dissolved inorganic constituents that build up in the steam generation process. This blowdown is cooled, then routed to the Refinery's cooling systemCooling Tower to be recycled. The underground water pipeline connection from the Cogeneration Project to the Refinery would be along the access road from Blaine road. The HRSG blowdown does not represent a wastewater discharge from the Cogeneration Project since it is used in the RefineryCooling Tower and does not affect the Refinery's wastewater discharge. Recycling the HRSG blowdown reduces the overall amount of fresh water necessary to operate the Refinery and the Cogeneration Project.

7.2 Wastewater Treatment and Disposal

The waste streams generated during normal Cogeneration Project operation represent the majority of the wastewater flows and are treated and disposed as described below.

7.2.1 Demineralization Plant Wastewater and Refinery Condensate Treatment System Waste

Filters are used to remove the relatively small amount of suspended solids in the raw water received from the Refinery. Filtration is required as a first step in the production of high quality BFW. After a 24-hour run, each of the three filters in the unit would be backwashed to remove the solids from the filter media. The backwash water is collected in a large tank (Neutralization Tank), which is periodically pumped to the Refinery for treatment. The anticipated route of the underground wastewater pipeline connection is along the east-west access road from the Cogeneration Project to the Refinery.

Ion exchange units are also used in treating raw water, condensate returned from the Refinery, and BFW sent to the Cogeneration plant from the Refinery in exchange for exported steam. Dissolved ionic species must be removed in order to generate high-pressure steam in the HRSGs without fouling or corroding the boiler tubes. The resins in the ion exchange units eventually become saturated as their capacity for removing ions is reached. It is then necessary to regenerate these resins with dilute sulfuric acid and sodium hydroxide. These chemicals, along with the removed ions and rinse waters, are collected in the Neutralization Tank, neutralized to a pH between 6.5 and 8.5, then pumped to the Refinery treatment system. The Refinery wastewater treatment system discharges treated water to the Strait of Georgia (see Section 8 for more details). The filter backwash is also part of this stream.

Condensate returned from the refinery must be treated to remove any trace oil before being used as boiler feedwater. A pre-coat system using powdered cellulose and activated carbon will be used to remove this trace oil. The cellulose used in this process will require periodic regeneration. The regeneration waste, including oily water and spent cellulose material, would be collected in a holding tank for dewatering and subsequent disposal. Small amounts of oily water produced from the dewatering process would be pumped to the refinery wastewater treatment plant. This volume of water is included in the Denim Plant Regeneration Water flow shown in table 7.1-1. The dewatered cellulose material would be disposed of along with other primary sludge generated within the Refinery.

7.2.2 Equipment Drains

Pumps, compressors, turbines, and other equipment generate a very small quantity of wastewater due to washdown, rainwater runoff, leakage, or periodic flushing operations within curbed areas. Since this wastewater has the potential to carry trace free oil, it is collected separately in a sump and pumped to the Refinery's oily water sewer for treatment before discharge to the Strait of Georgia (see Section 8 for more details). The anticipated route of the underground water pipeline connection is along the east-west access road from the Cogeneration Project to the Refinery.

7.2.3 Sanitary Waste

The Cogeneration project will have lavatories and for showers which will generate sanitary waste requiring treatment. This waste is estimated to average between 1 to 2-5 gpm, and would be collected in a sump and pumped to the Refinery's sanitary system for disposal. The Refinery's sanitary waste is sent to the Birch Bay Water and Sewer District

for treatment. The anticipated route of the underground sanitary wastewater pipeline connection is along the east-west access road from the Cogeneration Project to the Refinery.

7.2.4 Cooling Tower Blowdown

Approximately 7-10% of the water used by the Cogeneration Project cooling tower will be drained off to control the cooling tower water quality. The water drained off is pumped to the Refinery wastewater treatment system.

8. CHARACTERISTICS OF AQUATIC DISCHARGE SYSTEM

8.1 The Refinery Wastewater Discharge Point

Wastewater from the proposed Cogeneration Project would be sent to the Refinery's process wastewater treatment system. Refinery wastewater is treated and discharged to the Strait of Georgia under NPDES permit number WA-002290-0, effective November 1, 1999 until November 1, 2004 (Ecology 1999).

Refinery treated wastewater is discharged at the mooring area of the Refinery's pier approximately 2,000 feet from the shoreline at an approximate depth of 60 feet below mean low water level (Figure 8.1-1). The outfall is at the following coordinates:

- SE Quarter of Section 13, Township 39N, Range 1W
- Latitude 48°51'39"N, Longitude 122°45'26"W
- Washington State Plane, NAD83, North Zone 4601: N684685 feet, E1537069

The discharge diffuser is supported by pilings that also support the pier. The diffuser consists of a 20 inch diameter pipe with thirteen 4 inch diameter ports spaced 8 feet apart (Figure 8.1-2). The diffuser ranges from 3 to 6 feet from the seafloor.

The Refinery NPDES permit for this discharge ~~requires~~ [allows for](#) acute and chronic dilution zones. These have been defined in a "dilution ratio study" conducted in 1991 (ENSR 1991). The "zone of initial dilution" or acute dilution zone is 10% of the distance from the outfall structure to the furthest horizontal edge of the dilution zone, as measured in any spatial direction. The acute dilution zone therefore extends 26 feet from the discharge ports and from the seabed to the water surface.

The chronic dilution zone is specified by the Refinery's NPDES permit as a circle with a radius of 257 feet measured from the center of each of the diffuser ports. The chronic mixing zone extends from the seabed to the water surface.

Currents within this area are moderate (up to 1 knot) running predominantly parallel to the shoreline. Just seaward of the terminal, the seabed drops steeply to an average channel depth of 200 feet. Area depth contours run parallel to the shoreline. The marine floor consists mainly of marine muds and sands. The diffuser is situated normal to the prevailing tidal currents. The structural pilings enhance mixing as the piling shed vortices due to the flow around them (ENSR 1991).

8.2 Description of Resulting Aquatic Discharge

The industrial wastewater from the Cogeneration Project would be treated in the Refinery's wastewater treatment system. The Cogeneration Project wastewater effluents before treatment will have the physical and chemical characteristics listed in Table 7.1-1 (see Section 7 of this Technical Report). Stormwater runoff from the Project site would be treated and discharged in a separate system and under a separate NPDES Permit as described in Appendix F Technical Report on Water. The Cogeneration Project process wastewaters that would be discharged through the Refinery NPDES industrial wastewater permit originate as [three streams](#):

- Demineralization plant regeneration water (influent pretreatment wastewater) and refinery return condensate treatment system waste
- Collection of water and/or other minor drainage from various types of equipment,
- ☐ Wastewater with potential to carry trace oil (equipment sumps and other sources)
- CGT compressor blade wash water
- Cooling tower blowdown

After treatment in the Refinery wastewater treatment system, wastewater from the Cogeneration Project would be discharged along with the Refinery wastewater to the Strait of Georgia, adding about an average of 190 gallons per minute assuming 15 cycles of concentration in the cooling tower (see Table 7.1-1) to the Refinery discharge.

Wastewater from equipment sumps, boiler blow down, and demineralization of raw feed water would be routed to the refinery for treatment and discharge through the NPDES-permitted outfall (number 001) at the refinery's marine facility. Table 8.2-1 presents an analysis of the potential impact of the Cogeneration Project wastewater on the refinery's wastewater stream. As can be seen from this table, the impact is negligible or positive due to additional dilution in some cases. The impact analysis is based on the average discharge from the Refinery wastewater treatment study that was conducted ~~last~~ July, August, and September of 2001.

9. SPILL PREVENTION AND CONTROL

A Cogeneration Project Spill Prevention, Control, and Countermeasures (SPCC) Plan will be prepared and implemented. The SPCC Plan will describe the procedures and technologies in place to prevent and minimize the occurrence and consequences of chemical spills. The SPCC for the Cogeneration Project will be modeled after the existing SPCC Plan for the BP Cherry Point Refinery, with appropriate site-specific modifications.

The SPCC for the Refinery addresses the prevention, control, and countermeasures for the refinery, which has 50 crude oil and refined product storage tanks, representing a combined working capacity of 7,500,000 barrels. The existing SPCC includes the following sections:

1. Introduction
2. Facility Description
3. Spill Prevention Technology and Procedures
 - a. Facility Drainage
 - b. Bulk Storage Tanks
 - c. Facility Transfer Operations
 - d. Marine Terminal (Dock)
 - e. Truck Loading Rack
 - f. Refinery-Use Fueling Station
 - g. Spill Prevention Procedures
4. Inspections and Records
5. Refinery Security
6. Spill Prevention Training and Personnel Certification

Due to the differences in the operations of the Refinery and the Cogeneration Project, the SPCC for the Cogeneration Project will be less extensive, with no need for the following sections:

1. Bulk Storage Tanks
2. Facility Transfer Operations
3. Marine Terminal (Dock)
4. Truck Loading Rack
5. Refinery-Use Fueling Station

The Spill Prevention Technology and Procedures section will include information about the surface water collection systems and wastewater treatment that will be created, along with the interface for surface water handling with the Refinery.

The chemicals that would be used for Cogeneration Project operation include mineral or soybean oil used in the transformers on site, lube oil for CGT, STG and other rotating equipment, chemicals for [cooling tower and](#) water treatment, and ammonia needed to operate the SCRs.

Spill Prevention Technology and Procedures will include appropriate tank and piping design and construction standards; tank level controls; sophisticated monitoring and alarm systems, rapid pump and valve shutdown procedures and the use of secondary containment.

The Inspection and Records section of the SPCC will outline the schedule for inspections of petroleum product-containing vessels, and response to problems identified. Additionally, major maintenance of all connectors, alarm systems, and other facility components will be scheduled, along with the methods of documenting each activity.

Security systems employed for the Cogeneration Project will be discussed in the SPCC. Security measures include lighting, posting of signs, equipment safety controls, and perimeter security (fences, gates, guards, etc.).

The components of training necessary to properly implement the SPCC will be identified. This training will include introductory level awareness, and task-specific training. A critical part of this training is emergency response-related, including information about hazardous materials, safety and personal protective equipment.

9.1 Chemicals

9.1.1 Chemicals Used During Construction

Table 9.1-1 lists typical chemicals that are generally used at a construction project of this type. Estimated consumptive quantities are provided.

To minimize the potential release of chemicals during construction, best management practices will be employed. These will include good housekeeping measures, inspections, containment facilities, minimum on-site inventory, and spill prevention practices. Construction personnel will be instructed regarding the management requirements, and the Applicant's on site Project Manager will be responsible for their implementation.

The compressed gases listed in Table 9.1-1 are typically present during the construction of a generation plant. These gases will be properly stored when not in use, in accordance with all applicable local, state, and federal regulations.

All construction waste materials will be collected, deposited, and stored in appropriate containers provided by a licensed Solid Waste Management Contractor. The Waste Management Contractor will remove the containers and recycle or dispose of the material in accordance with applicable regulations. No construction waste material will be burned or buried on site. The on site Project Manager will instruct all site personnel regarding proper waste disposal procedures.

Portable sanitation units containing chemicals used to treat waste will be used during construction of the power plant. These units will be maintained on a regular basis, and a licensed Sanitary Waste Management Contractor will collect waste from the units for disposal in accordance with applicable regulations. 500-gallons of sanitary waste per day is anticipated during the construction phase.

9.1.2 Chemicals Used During Operation and Maintenance

The chemicals that would be used and stored at the generation plant during operation and maintenance are listed in Table 9.1-2.

A number of safeguards will be incorporated to mitigate the risks of a release to the environment. These include but are not limited to secondary containment, tank overflow protection, routine maintenance, safe handling practices, supervision of all loading/unloading by plant personnel and the truck driver, and appropriate training of operation and maintenance staff.

Natural gas pipelines are the only practical means of transporting and using natural gas. Various codes, regulations, and industry standard designs define how natural gas pipelines are designed and operated.

Very little waste would be produced during the operation and maintenance of the cogeneration plant. The used lubrication and transformer oils, small quantities of used paints, thinners, and solvents used during operation will be recycled or disposed of in accordance with federal, state, and local regulations. Table 9.1-3 lists the anticipated waste quantities (not including wastewater) that will be generated during operation of the Cogeneration Project.

Any dangerous wastes generated by the plant will be managed to ensure compliance with Washington Dangerous Waste Regulations (173-303 WAC). Dangerous wastes will be limited to solvents and paint wastes generated during maintenance activities. A generator number has not yet been assigned.

Consumables used during operation would be brought to the Cogeneration Project site by truck. The actual route used for transport would depend on the location of the supplier, but it is believed that Interstate 5-to-Grandview Road (State Route 548) would be the principal transportation route used. Additional details on transportation anticipated to be used is provided in Appendix I: Technical Report on Transportation.

The anhydrous ammonia would be received via a tanker truck. ~~Typically each truck holds 2,000 to 6,000 gallons.~~ The Cogeneration Project would use up to ~~940,000~~ 870,300 lbs (~~~182,000~~ ~168,500 gallons) of ammonia per year. The number of round trips is estimated to be about 23 per year.

Caustic solution is typically shipped from Tacoma, WA (Pioneer), or from Dow Chemical in Fort Saskatchewan, Alberta Canada. The Cogeneration Project would use 83,000 gallons per year for water treatment and would have a storage capacity of 8,000 gallons. The number of round trips is estimated to be 28 per year for caustic solution.

Sulfuric acid is typically shipped from Anacortes, WA (General Chemical). The Cogeneration Project plant would use about ~~40,000~~ 80,000 gallons per year for cooling water treatment and boiler feedwater treatment and have two tanks with a combined storage capacity of about ~~8,000~~ 16,000 gallons. The Cogeneration Project would require an estimated 13 round trips per year for sulfuric acid.

For the BFW chemicals (oxygen scavenger, neutralizing amine), In addition to caustic and sulfuric acid mentioned above, the Cogeneration Project would have on-site storage capacity of various other water treatment chemicals used to create boiler feed water such as diethyl hydroxylamine oxygen scavenger, morpholine corrosion inhibitor, polyquaternary amine polymer, and di- and tri-sodium phosphate PH/scale control agent. Storage quantities vary from 50-500 gallons and would use about 200 to 300 gallons per year. The Cogeneration Project usage rates would require an estimated three round trips per year chemical. The water treatment system will also use anion and cation resin to demineralize the boiler feedwater. The Cogeneration Project would receive these chemicals from Baker Chemicals or similar company who manufactures them in various locations.

Cooling tower chemicals would be added to ensure efficient cooling and to prolong equipment life. Chemicals and estimated quantities typically added would include Sulfuric Acid, as mentioned above, 150,000 gallons per year of 15% Sodium Hypochlorite and 10,000 gallons per year each of Zinc/Phosphonate Solution and Polyacrylamide polymer.

Treatment of refinery condensate to remove any trace oil will be done with a pre-coat system using Ecosorb powdered cellulose and activated carbon. The regeneration waste, including oily water and spent cellulose material, would be collected in a holding tank for dewatering and subsequent disposal. Small amounts of oily water produced from the dewatering process would be pumped to the refinery wastewater treatment plant. This volume of water is included in the Denim Plant Regeneration Water flow shown in table 7.1-1. The dewatered cellulose material would be disposed of along with other primary sludge generated within the Refinery.

Usage rates for the cellulose and activated carbon would vary but are estimated to be 146,000 lb/year.

Rotating equipment in the Cogeneration project would use lubricating oil to cool and lubricate bearings. To conserve oil, oil may be reclaimed. When oil properties no longer provide for effective lubrication, the oil may be sent off site to be reclaimed or reprocessed. Estimated quantities of lube oil to be used are 25,800 gallons per year. The Steam turbine also uses oil in a hydraulic control system. Lubricating oil could be used for this purpose but a segregated control oil system may be provided by the steam turbine vendor.

Transformers use oil for cooling. While this oil does eventually require replacement to control contaminants that eventually accumulate, this oil can be reclaimed to prolong its life. The estimated rate of transformer oil use is very small.

A small amount of Hydrogen is used to cool generator windings. The estimated usage quantity is 562,100 SCF/year. A small amount of Carbon Dioxide is also used to provide fire protection for certain equipment. In the absence of fire involving this equipment, the normal rate of this carbon dioxide use is negligible.

The Cogeneration Project features a closed-loop water/glycol cooling system for selected ancillary equipment. Propylene glycol and nitrate/borate corrosion inhibitor would be used to maintain cooling efficiency and promote equipment life. The usage rates for these chemicals are considered insignificant.

9.2 Cogeneration Project Storage Tanks and Sumps

Table 9.2-1 identifies storage tanks and major equipment that would store liquids during operation of the Cogeneration Project. The following gives a brief description of the spill prevention and control features to be installed with each tank:

The demineralized water storage tank, returned condensate storage tank and the demineralization system neutralization tanks would not be provided with spill containment.

The following tanks hold diesel fuel oil for the emergency generator and fire water pump or lube oil for major rotating equipment. These tanks will be provided with secondary containment for spill control with adequate freeboard for rainwater if required.

The fire pump diesel fuel storage tank will be a horizontal tank with a capacity of approximately 460 gallons and dimensions of 4 feet diameter x 5 feet long. The diesel generator diesel fuel storage tank will be a vertical tank with a capacity of approximately 1,500 gallons and with dimensions of 6 feet diameter x 8 feet high.

The steam turbine lube oil storage tank will be a rectangular tank with a capacity of approximately 7,200 gallons and with dimensions of 24 feet long x 12 feet wide x 7 feet high. Depending on the supplier of the steam turbine, the electro-hydraulic control oil system may be integrated with the lube oil system or it may be a standalone system.

One combustion turbine lube oil storage tank will be provided for each of the three CGTs. Each tank will have a capacity of approximately 6200 gallons and with approximate dimensions of 28 feet long x 10 feet wide x 4 feet high. These lube oil tanks are located inside the accessory module that is furnished as part of the CGT vendor scope of supply.

Transformer Oil: Transformers will be installed within secondary containment areas that will hold the transformer's volume plus an adequate freeboard to accommodate rainwater.

Anhydrous Ammonia Tank: A secondary containment area will be constructed around the ammonia tank that will contain 150% of the working volume. The additional containment is provided to accommodate water from a deluge spray system and rainwater.

Caustic Tank: The caustic tank will be surrounded by a secondary containment area and sized with sufficient freeboard for rainwater.

Acid Tanks: The two acid tanks will be located within a secondary containment area lined with an acid-proof coating and sized with sufficient freeboard for rainwater.

Steam Cycle Chemicals: Oxygen scavenger, neutralizing amine, corrosion inhibitors and phosphate storage tanks are located indoors and will be contained in a curbed area sufficiently sized to contain the single largest storage tank.

Cooling Tower Chemicals: These chemicals will be stored in vertical cylindrical tanks as described in Table 9.2-1 or in totes provided by the chemical vendor near the cooling tower in a curbed area sufficiently sized to contain the contents of the single largest storage tote.

Oil-Water Sewer: The BP Cogeneration Facility will be provided with an oil-water sewer (OWS) system that collects selected equipment drains and rainfall and washdown runoff from within curbed areas that could carry trace oil. Collected drainage and runoff will be pumped to the existing Refinery treatment system. Table 9.2-1 lists the underground sumps that are included in this system.

10. SURFACE WATER RUNOFF

10.1 Stormwater Collection and Treatment During Construction

Best Management Practices (BMPs) as described in the Stormwater Management Manual for Western Washington would be used to control stormwater runoff during construction and minimize soil erosion. The Stormwater NPDES Permit application for construction activities is provided in Appendix F: Technical Report on Water. Diversion ditches will prevent runoff from areas outside the Cogeneration Project site from entering the site. Stormwater runoff from within the Cogeneration Project site will be contained, collected, and routed to the stormwater treatment and detention system. Silt fences and temporary swales on the construction site would lead runoff to the treatment and detention system. Perimeter silt fences around the construction zone will be installed to remove sediment from runoff before it reaches the site boundary. Additional localized silt fencing will be used as required during construction to minimize erosion and transport of soil. Temporary swales would be constructed to accommodate areas being excavated or filled. Once the preliminary cut-and-fill work is complete, the swales will likely remain in place until final grading. Wherever possible, temporary swales will be incorporated into the permanent stormwater collection system. The perimeter silt fence will not be removed until the site has been stabilized. In general, the stormwater treatment and detention system will consist of oil/water separation system equipped with a shutoff valve in case of an accidental release for containment. Emergency cleanup equipment and supplies will be available on-site for rapid response. Stormwater will be discharged from the oil/water separation system into a final treatment and detention pond properly sized in accordance with Whatcom County and Washington Department of Ecology (WDOE) requirements, and then eventually discharged to wetlands from the treatment/detention pond.

As elements of the permanent stormwater collection system are installed within the Cogeneration Project site (see discussion below), they will be used to contain, collect, and treat construction runoff. Silt fencing intended to prevent sediments from entering will protect inlets to the permanent system. Seeding and mulching will be used where practical for slope stabilization as rough grading is completed.

Containment pits or other means of confinement will be provided locally near each potential source of contaminating materials to provide for protection against spillage. A Stormwater Pollution Prevention Plan (SWPPP) will be established prior to commencement of construction activities.

10.2 Stormwater Control During Operation

The Stormwater NPDES Permit application for Cogeneration Project operation is provided in Appendix F: Technical Report on Water. In summary, the Cogeneration Project site will be divided into three primary drainage areas for the purposes of runoff design. The first area will consist of the switchyard area on the eastern portion of the site. The second area will consist of the remainder of the developed site, which includes the power block, ~~air-cooled condensers~~[cooling tower](#), and administrative functions. The third will be stormwater that could become impacted from a storage tank accidental release.

The switchyard area will be surfaced with crushed rock to allow some percolation into the soil below. The area would be graded at about 1 percent slope so as to sheet flow excess runoff towards a collection system consisting of swales, catch basins, manholes and underground pipe.

Most of the remaining plant areas will be asphalt-paved, [covered with crushed rock, grass](#) or covered with buildings [or enclosures](#). The finish surfaces in this area would be sloped from a high point located near the center of the main pipe rack towards low points located along the edge of the plant roads. Runoff would be sheet flow across the site towards a collection system similar to that described above. All surface runoff will be captured by the surface drainage system then be directed through an underground piping system to the stormwater treatment and [rdetention](#) system. The stormwater treatment and [rdetention](#) system consists of an oil/water separation system equipped with a shutoff valve in case of an accidental release for containment. Emergency cleanup equipment and supplies will be available onsite for rapid response. Stormwater will be discharged from the oil/water separation system into a final treatment and [rdetention](#) pond properly sized in accordance with Whatcom County and Washington Department of Ecology (WDOE) requirements. Stormwater will be discharged to wetlands from the [rdetention](#) pond. Additional details are provided in Appendix F: Technical Report on Water.

The third area for stormwater collection results from stormwater accumulating within the secondary containment structures for outside tanks and chemical storage areas. This stormwater is expected to be a small volume and will be separated from other stormwater because of releases that could potentially occur from the tanks. This stormwater will be collected and routed to the Cogeneration Project wastewater system. The water would leave the Cogeneration Project site along with the plant wastewater, be discharged into the existing refinery wastewater treatment system, and then processed by the refinery's wastewater treatment plant.

11. EMISSION CONTROL

11.1 SCR Technology

The Cogeneration Project will use the Best Available Control Technology (BACT) to minimize atmospheric emissions from the Project. An evaluation of BACT for the proposed plant and emission levels is provided in Part III Appendix E: Technical Report on Air. The Prevention of Significant Deterioration (PSD) Permit Application is also contained within Appendix E and provides in-depth analyses of emission calculations and potential air impacts associated with the Cogeneration Project. The following sections provide an overview of the selective catalytic reduction (SCR) and oxidation catalyst systems as well as their design, control and operating performance.

Appendix E provides estimates of CGT and HRSG stack emissions from the Cogeneration Project using BACT, General Electric 7FA CGTs, and natural gas fuel with an annual average and peak sulfur content of 0.8 and 1.6 grains per standard cubic feet, respectively.

The proposed Cogeneration Unit will permit BP to shut down boilers and would otherwise enable the refinery to reduce criteria pollutant emissions. The result is a net reduction in these emissions from the Cherry Point site. Details of these emission reductions are provided in [Table 2.3-3](#). The remainder of this section discusses air emissions from the proposed Cogeneration Unit without reference to [the expected offsetting reductions in reducing](#) emissions from the refinery.

SCR Technology

The SCR and oxidation catalyst systems will be integrated within each Heat Recovery Steam Generator (HRSG), which recovers waste heat from hot CGT exhaust gas (flue gas). SCR is considered BACT for the Cogeneration Project and is commonly used for post combustion NO_x reduction stack gas treatment approach for HRSG installations. As a proven technology, the use of SCR satisfies the required criteria for air emission control level and has a good record of reliability and catalyst life in clean, gas-fired service.

SCR utilizes a metal, acrylic, or zeolite base type catalyst to selectively promote a rapid chemical reaction between ammonia (NH₃) and nitrogen oxides (NO_x). The basic chemical reactions are:



As shown, these chemical reactions are typically achieved with the proper introduction of anhydrous or aqueous ammonia solution in the flue gas stream. Typical conversion efficiency range is 80 to 90% of NO_x. Ammonia injection rates would be controlled to limit NO_x emissions, and would be managed to limit ammonia "slip" (unreacted ammonia as measured in flue gas existing the HRSG stacks) to a [n-average of 5 ppmvd @ 15% O₂ on an annual basis. The maximum 24 hour average ammonia slip would be limited to 10 of 5 ppmvd @ 15% O₂.](#)

The typical operating temperature range for a conventional SCR is about 600 to 800°F, which is optimum for catalyst activity and selectivity. Lower temperature catalysts that are available for operating temperatures between 400 and 500°F are more expensive and require more catalyst per unit conversion (activity and efficiency drop off significantly with temperature). In addition, low temperature catalysts are more prone to deactivation due to sulfur in the flue gas stream.

The following types of SCR technology are commercially available:

- Low temperature type catalyst - These platinum group base catalysts offer an effective NO_x reduction at specified temperature ranges, namely:
Platinum base only catalyst operates most effectively at 300 to 400°F.
Modified Platinum base catalyst operates most effectively at 480 to 600°F.
- Moderate temperature type catalyst - Most commercial SCR installations use Vanadium base formulations with a specified operating temperature range of 550 to 800°F for peak NO_x conversion efficiency. The catalyst loses its selectivity when the flue gas temperature exceeds 795°F. This temperature constraint determines the flexibility of the SCR location.
- Higher temperature type catalyst – One type of this catalyst comprises a catalytic layer of V₂O₅/TiO₂ bonded to an inert ceramic honeycomb configuration. Another example for high temperature application is the composite Zeolite SCR catalyst. This catalyst extends the operating temperature for the SCR reaction from about 700°F to about 1,100°F.

11.1.1 System Design

The Project will use the moderate temperature SCR system and will have the following basic operating modes:

- Base load natural gas firing without duct firing,
- Base load natural gas firing with duct firing, and
- Minimum load natural gas firing.

Natural gas would be the only fuel used for firing the CGT and duct burners. SCR and CO oxidation catalysts in the HRSGs would further reduce the NO_x and CO emissions to the required levels.

During full load operation at ISO conditions, CGT exhaust would contain a NO_x emission concentration of 9 ppmvd (@15% O₂) when firing natural gas during normal operation. With SCR, the BACT emission level of NO_x would be reduced to a maximum of 2.5 ppmvd (@15% O₂) on an annual basis.

The estimated SCR catalyst volume for NO_x removal to BACT levels would be approximately 1,600 ft³ per HRSG or 4,800 ft³ for all three HRSGs. Normal catalyst life expectancy would be between 3 and 5 years.

A simplified flow diagram of the emission reduction system is presented in Figure 11.1-1. As shown, the mechanical components of the system would consist of a reactor chamber

with a modular catalyst bed and an ammonia distribution and injection system. The ammonia would be injected into the flue gas stream, upstream of the SCR catalyst. There are no moving parts within the HRSG, and other than spent catalyst replaced once every few years, the SCR process would produce no solid or liquid waste products.

Major supporting facilities for the SCR system would include the following:

- Ammonia storage system.
- Ammonia injection control unit and dilution air blower skid.
- Associated interconnecting piping, instrumentation such as stack analyzers and electrical devices.

11.1.2 SCR Catalyst

The SCR system tentatively selected for the Cogeneration Project consists of a moderate temperature, titanium/vanadium catalyst impregnated on a ceramic honeycomb-type modules that are stacked within the HRSG. The modules would be field installed. The cross-sectional pattern would be rectangular and sized to meet the BACT NO_x reduction requirements and an acceptable HRSG pressure drop.

11.1.3 Ammonia Storage System

The ammonia storage system will be located within a containment area and will be provided with a delivery truck unloading area, a horizontal cylindrical storage tank, interconnecting valves and piping to feed the ammonia flow control unit.

The working capacity of the storage tank would be about ~~11,650~~12,000 gal, which will be sufficient for storing ammonia for approximately four weeks of operation. Safety devices such as pressure/vacuum relief valves, liquid overflow protection devices, isolation block valves, alarms, water spray (above storage tank) and associated instrumentation would be incorporated into the detailed design of this storage system.

11.1.4 SCR Emission System Operation

A simplified schematic diagram of the control system and support facilities that would feed the desired amount of anhydrous ammonia to the system is shown in drawing AD-00-4300-00102. Ammonia would be supplied to the dilution and vaporization skid via a flow control unit integrated in the skid assembly. Air from the dilution air blowers would be electrically heated and would be mixed with the ammonia for vaporization. The blowers would operate at a constant speed and the ammonia flow would be controlled via a flow control valve to achieve the ammonia levels necessary for the required NO_x reduction. Demand would typically be determined either via an inlet NO_x analyzer or by predetermined load versus demand curves programmed into the DCS. This feed-forward signal configuration will rapidly adjust ammonia flow to follow load swings. The ammonia flow will be secondarily controlled (trimmed) via a feed back signal from the outlet NO_x analyzers. This will allow rapid achievement of the outlet NO_x specified with minimum oscillation or instabilities occurring in the control system.

At the ammonia injection grid, ammonia will be evenly injected upstream of the SCR reactor. A pre-determined minimum distance between ammonia spray nozzles and the

catalyst reactor will also be established to effectively achieve even distribution over the catalyst bed. Manual valves and local flow indicators will also be provided at each injection line to provide zoned ammonia flow tuning ability to insure a good match between the NO_x in the flue gas and the ammonia across the entire HRSG. These valves will be set during initial operation and will not require further adjustment unless operating conditions are significantly changed.

11.2 CO and VOC Oxidation and Control

BACT for the Cogeneration Project for CO and VOCs is the use of high efficiency combustion turbines, operational control and CO oxidation catalyst (see Appendix E-PSD Application for more details). During full load operation at ISO conditions, Cogeneration Project CGT flue gas would contain a CO emission concentration of approximately 9 ppmvd @ 15% O_2 . CO and Volatile Organic Compounds (VOCs) emissions in the flue gas stream will be reduced to BACT levels by an oxidation catalyst reactor, which would be located in each HRSG system. As the flue gases pass over the noble metal catalyst, CO and VOC will be converted to CO_2 and water vapor. This oxidation process will not require any chemical reagent for catalytic reaction, and will typically reduce CO emissions by 80 to 90%. The emission level for CO leaving the HRSG will not exceed 2 ppmvd @ 15% O_2 during normal operation.

The estimated volume of the oxidation catalyst will be about 330 ft^3 per HRSG or a total volume of 990 ft^3 for all three HRSGs with a service life of 3 to 5 years. Reduction of VOC will be highly dependent upon the specific organic compounds present and the catalyst operating temperature. [The PSD Permit application requests a VOC emission limit of 6.9 lb/hr.](#)

11.3 SO_x and Particulate (PM_{10}) Control

Sulfur dioxide (SO_2) is formed exclusively by the oxidation of the sulfur present in natural gas fuel. The emission rate of SO_2 is a function of combustion efficiency of the source and the sulfur content of the fuel since virtually all fuel-bound sulfur is converted to SO_2 . Some of the SO_2 may be converted to SO_3 , which in turn can form trace H_2SO_4 (sulfuric acid) mist. The BACT for SO_x control is the use of low sulfur fuel such as natural gas. The natural gas is expected to have a maximum sulfur content of 1.6 grains per 100 scf, and an average sulfur content of no more than 0.8 grains per 100 scf. The use of low sulfur fuel is listed as BACT for all the CGTs identified in the search.

When SO_2 is present in the flue gas stream, a portion will oxidize to SO_3 and its subsequent reaction with moisture in the flue gas may result in the formation H_2SO_4 . The natural gas supplier would periodically report the average natural gas sulfur content. The temperature profile at the cooler end of the HRSG would be carefully designed to minimize the effects of condensation of H_2SO_4 and resulting corrosion. Acid gas dew point temperatures would be expected to be below 200°F.

In the presence of excess ammonia, SO_3 in the flue gas can also form ammonium salts ($(\text{NH}_4)_2\text{SO}_4$ and NH_4HSO_4). Since these compounds would form in the temperature range of 350°F to 450°F, it will be likely that SO_3 will preferentially form ammonium salts rather than H_2SO_4 . Ammonium sulfates would either be emitted as PM_{10} (particulate) emissions or would be deposited on the cooler heat transfer surfaces within the HRSG. These salt deposits would be removed with a periodic washing operation or the use of high-pressure air or nitrogen gas to blast-clean the tube surfaces.

Particulate emissions measured in the HRSG stacks using EPA method 201, 201A and 202 from natural gas combustion sources consist of ash from the fuel and include filterable particulate of carbon and hydrocarbons resulting from combustion, but this is actually only about 10% of the particulate which is measured by the test equipment. Much of the remainder is “condensable” particulate which are predominately sulfates, ammonium sulfate and ammonium nitrate. A brief discussion of the types of materials measured as particulates by this EPA test method is provided in Section 3.2.

~~incomplete combustion. Therefore, units firing fuels with low ash contents and high combustion efficiency exhibit correspondingly low particulate emissions.~~ The use of low ash and low-sulfur fuel such as natural gas, and good combustion control can be concluded to represent BACT for PM₁₀ control for the proposed CGTs. The combination of low ash fuels and good combustion control is listed as the BACT for the majority of CGTs.

11.4 Toxics Emission Control

The toxic emissions from the Cogeneration Project are a subset of the PM₁₀ and VOC emissions. Add-on controls are not generally required for PM₁₀ and VOC emissions from natural-gas-fired CGT facilities. The same controls that are considered BACT for PM₁₀ and VOC emissions would be considered BACT for toxic emissions.

11.5 Stack Analyzers

Continuous emission monitoring (CEM) of the stack gases will be provided based on the parameters listed below. Both local and remote (control room) monitoring will be required, and each CGT/HRSG train would have a dedicated Continuous Emission Monitoring System (CEMS). The CEMS will monitor emissions of NO_x, CO, NH₃ and O₂ from the HRSG stacks and transmit to the Data Acquisition System (DAS). The CEMS will comply with the provisions of the air permit issued by EFSEC.

The basic equipment would consist of:

- Three sampling systems with conditioning systems to prepare samples for analysis.
- Three sets of gas analyzers to measure the concentration of NO_x, CO, NH₃, and O₂, in stack flue gas.
- Three CEMS shelters.
- A common DAS system for monitoring, alarming, and regulatory compliance reporting.
- Programmable Logic Controller (PLC).

The CEMS would record the HRSG stack emissions for the following:

- NO_x
- CO
- O₂
- NH₃

The CGT control system and plant Distributed Control System (DCS) will provide additional parameters:

- Load in megawatts of each gas turbine.
- Volumetric flow rate of natural gas to each gas turbine in standard cubic feet per minute.
- Volumetric flow rate of fuels to each HRSG Burner Management System (BMS).
- Temperature of each HRSG stack.

The CEMs system will provide the following signals to the DCS:

- NO_x concentration in ppmvd corrected to 15% O₂
- CO concentration in ppmvd corrected to 15% O₂
- O₂ concentration in percent
- NH₃ concentration in ppmvd corrected to 15% O₂

12. OPERATION WORKFORCE AND MAINTENANCE ACTIVITIES

12.1 Plant Operation Workforce

The operation of the Cogeneration Project would require about 30 full-time employees. The Cogeneration Project would be staffed in shifts 24 hours per day for seven days per week. The day shift during weekdays would have the largest number of personnel at the plant and is expected to be about fifteen (15) personnel, while the off-shifts and weekend crew would total four (4) personnel.

For scheduled maintenance, the number of personnel would increase. This number depends on the specific scheduled tasks of each maintenance period and would vary between 5 and 10 maintenance personnel per shift. The maintenance periods are expected to vary in duration from two weeks per year to 18 weeks per year (once every six years).

12.2 Cogeneration Project Operation Schedule

A schedule for engineering, procurement, construction and commissioning of the Cogeneration Project is presented in Figure 12.2-1. Under the assumptions given, the Cogeneration Project could start commercial operation at the beginning of 2006. Since the Cogeneration Project provides benefits to the Refinery, an earlier construction start date would be likely. The Cogeneration Project is designed to allow maintenance to be scheduled without a complete shutdown of the facility (see Section 12.3 below for the expected maintenance schedule).

12.3 Plant Maintenance Schedule

The anticipated maintenance schedule during operation of the Cogeneration Project is provided in Table 12.3-1, along with estimated manpower requirements. As shown on the table, the maximum maintenance effort would occur every sixth year of operation when approximately 4,000 man-hours (about 80 man weeks) would be necessary for major inspection and overhaul of equipment. During the major inspection and overhaul maintenance period, maintenance on each gas turbine generator would take about six weeks with only one CGT undergoing maintenance at a time (18 weeks total for all three CGTs). The Cogeneration Project ~~would~~ may not be completely shut down for any of the planned maintenance periods.

13. CONSTRUCTION OF THE COGENERATION PROJECT

13.1 Construction Schedules

A typical construction schedule for the Cogeneration Project is presented in Figure 12.2-1. This schedule supports a 2006 start up date, ~~it is likely the commencement of construction would take place sooner.~~

13.2 Construction Workforce

The overall Cherry Point Cogeneration Project schedule assumes an average ~~50 to 55~~ 40 to 48 hour workweek for construction workers. Table 13.2-1 provides an estimate of the work force anticipated during construction of the Cogeneration Project.

The construction plan is to operate on single shifts with spot overtime as necessary to maintain specific milestones. A second shift could be instituted as necessary to accommodate a particular construction activity or meet a critical milestone. At present, the commissioning effort would be supported with a second shift.

Dayshift hours would commence between 6:30am and 7:30am and conclude between 5:00pm to 6:00pm. The Cogeneration Project will coordinate with the Refinery to stagger the workforce start/stop times to minimize traffic congestion and maximize the efficiency of support resources. Lunch hours would also be staggered to minimize congestion on the roads and supporting areas.

If a second shift were needed, the number of workers assigned would be much lower than the number of workers in the first shift. The second shift would typically have one shift start at 6:00pm and would conclude at 4:00am.

The management of the Cogeneration Project workforce would be coordinated with other concurrent projects within the Refinery to minimize congestion and offsite impacts. This type of coordination effort would not be new for the Refinery. The Refinery conducts major unit shutdowns every three years, typically ending up with at least three individual dayshift start/stop times to minimize congestion and delays of projects.

13.3 Plant Construction Sequence

13.3.1 Existing Conditions

The Cogeneration Project site would be located on unimproved land that is zoned Heavy Impact Industrial. The Cogeneration Project site is relatively flat (about 1 percent grade) and contains grasses, scrubs, and small trees (mostly hybrid poplars planted by BP for harvesting). The Cogeneration Project site would be cleared and graded to allow stormwater drainage during construction by sheet flow into a perimeter trench system for collection and disposal. There are no streams within the Cogeneration Project site. Wetlands exist within the Cogeneration Project site and are shown on Figure 13.3-1. These wetlands represent a sensitive area that would be impacted by the Cogeneration Project. Detailed delineation and analysis of the wetland functions and values are provided in Appendix H: Technical Report on Plants and Animals.

13.3.2 Early Activities

The early construction activities begin in the home office of the contractor during the engineering phase with development of project schedule, plant layout, sequence of work, and project procedures, constructability review, identification of work packages, etc. The construction activities at the site commence with mobilization as discussed below.

13.3.3 Mobilization

A core team of the contractor's construction staff would mobilize to the site initially and set up temporary construction offices. The team would establish environmental, health and safety practices emergency response procedures as well as work with the Owner in fostering community relations. The team would identify and liaise with local resources for construction material and services and also establish logistics.

13.3.3.1 Construction Offices, Parking and Laydown Areas

Mobile trailers or similar suitable facilities (e.g., modular offices) would be used as construction offices for owner, contractor, and subcontractor personnel. Construction laydown and parking areas would be adjacent to the site and are shown in drawing AD-00-4300-00108. A security fence would be installed around the perimeter of the Site, as well as the perimeter of the laydown areas.

13.3.3.2 Emergency Facilities

Emergency services would be coordinated with the BP Cherry Point refinery, the local fire department, and hospital. First-aid kits would be provided around the site and regularly maintained. Personnel trained in first aid would be part of the construction staff. Fire extinguishers would be available throughout the site at strategic locations at all times during construction.

13.3.3.3 Construction Utilities and Site Services

Temporary utilities would be provided for the construction offices, laydown area, and the Cogeneration Project site. Temporary construction power would be obtained from the Refinery. Area lighting would be provided and strategically located for safety and security.

The contractor would provide for the following site services, coordinated as applicable with the existing Refinery programs:

- A site-specific Environmental Health and Safety Plan covering training, orientation, implementation and auditing will be developed and will incorporate refinery EH&S requirements,
- Stormwater Pollution Prevention Plan (SWPPP) will be developed prior to site preparation activities
- Site security,
- Site first aid facility,
- Construction testing requirements (NDE, Hydrostatic testing, etc.),

- Site fire protection and extinguisher maintenance,
- Furnishing and servicing of sanitary facilities,
- Trash collection and disposal, and
- Disposal of hazardous materials and in accordance with all laws, ordinances, and regulations.

13.4 Construction Operations

Initial activities upon mobilization would be establishment of the field construction office, site survey and site parking and laydown area preparation work. The wetlands and monuments identified by the Owner for preservation would be fenced off for protection.

Site Security: A site security system will be established prior to staging materials on the site and in laydown areas. The site and laydown area will be fenced with an 8-foot tall combination chain link and barbed wire fence. Site access will be controlled for personnel and vehicles.

Housekeeping: During construction, dust will be controlled as needed by spraying water on dry, exposed soil. Work areas will be organized and cleaned as required at the end of the day. Measures would be taken to prevent mud from accumulating on Grandview road from Cogeneration Project construction activities.

Erosion Control: Erosion control measures will be used in accordance with the requirements of the SWPPP that would be developed to include specific construction activities of the project. Erosion control measures may include such items as silt fences, hay bales, rock bases, temporary water conveyance structures, and detention ponds.

Dust Control: Dust will be controlled during construction by standard dust suppression using water sprays. The amount of water anticipated for dust control could be up to 7 million gallons over the ~~23-month duration of the~~ construction period. The EPC contractor will supply this water. The application of water will be at a rate to maintain a moist surface, but not create surface water runoff or erosion conditions.

Sanitation: Construction personnel will place field toilets and temporary holding tanks on site for use. These toilets will be serviced frequently by an outside service firm. During construction, potable water will be provided until the permanent water supply system is installed, or the contractor may provide potable water in containers.

13.4.1 Site Preparation

All site preparation would be completed using conventional methods of construction. The site is generally dry and dewatering is not expected to be required. Vegetation that would be cleared at the Cogeneration Project site includes grasses, scrubs, and small trees (mostly hybrid poplar planted by BP for harvesting). Conventional construction equipment, including bulldozers, front-end loaders, trucks, tractor scrapers, and graders would be used for site preparation. If cultural resources or soil contamination is encountered during excavation and grading, BP will halt construction in the suspect area and notify the pertinent regulatory agencies and take appropriate actions.

Prior to site preparation activities a SWPPP would be developed. The proposed plant site would be cleared and graded to a level surface. To the extent possible, excavated material of acceptable quality would be retained on the site in designated locations using proper erosion protection methods for reuse as backfill. Excess material to be removed from the site will be disposed of at an acceptable designated location.

After the initial cut and fill, a rough grading of the plant site would be performed. The access roads to the plant site from Grandview, Brown, and Blaine roads would be prepared and rough graded. Graded areas would be compacted, free from irregular surface changes, and sloped to drain. The graded surface would be provided with a gravel surface. Cut and fill slopes for permanent embankments would be designed for Seismic Zone 3 with the use of retaining walls as required.

During site preparation, an erosion control and temporary stormwater drainage system will be installed. This system will convey surface water runoff into the storm drainage control system. In addition, all earthworks necessary for temporary construction activities will be completed.

Areas to be backfilled would be prepared by removing unsuitable material and rocks. The bottom of an excavation would be examined for loose or soft areas. Such areas would be excavated fully, backfilled with suitable material and compacted. Backfilling would be performed in a controlled manner in layers of uniform specified thickness to achieve the desired density. The amount of import fill that would be required for the site preparation is estimated to be 126,000 yd³. The contractor will supply fill materials from permitted local sources.

Temporary roads, plant perimeter roads, laydown and parking areas, and other work areas would be provided with a gravel surface [as required](#). The total amount of gravel aggregate and sand base materials required for site preparation is expected to be about 28,200 yd³. The source of this gravel aggregate and sand material would be determined by the contractor, but is expected to be from local permitted sources.

Undeveloped areas to the north and the southeast of the plant have been identified for use as construction laydown areas (Laydown Areas 1 through 4). These areas would be graded and would be unpaved or surfaced with aggregate during construction [as required](#). Approximately 36 acres of land would be used for construction laydown. The Cogeneration Project plant layout and the areas that would be used for construction laydown and construction parking are shown in drawing AD-00-4300-00108. Construction laydown and parking areas would be adjacent to the site. A security fence will be installed around the perimeter of the site, as well as the perimeter of the laydown areas. Construction worker entrance would be through a security gate on Blaine Road on BP property.

If additional laydown area is needed for the construction of the Cogeneration Project, Laydown Area 5 (see drawing SK-BE7608-MD-006 Rev. A) could be developed and used. Laydown Area 5 is located on BP owned land adjacent to the pipelines near the docking facilities. Laydown Area 5 would only be on delineated uplands and could add about 10 acres to the total laydown area.

13.4.2 Foundations and Roadways

After site preparation and rough grading is completed, the contractor would install the piling and concrete foundations required for the support of the combustion and steam turbine generators, HRSGs, stacks, pipe supports, electrical equipment, and other miscellaneous equipment items, tanks and support facilities. Pile-supported concrete foundations would be used to provide support for all major equipment items, major building columns and pipe rack supports. The piles would be 60 to 80 feet in length. Pile type, length, and configuration would be based on geotechnical investigations. Construction of these foundations would require the use of heavy equipment, including pile-driving equipment, excavation and backfill equipment, concrete-pumping equipment, and concrete-finishing equipment. In addition, light and medium duty trucks, air compressors, generators, and other internal combustion engine-driven equipment would be used.

On-site roads and parking areas will be constructed with asphalt concrete over a compacted-engineered subbase. The perimeter and equipment access roads would be constructed with aggregate placed over a compacted-engineered subbase.

13.4.3 Facility Installation

The facility installation work commences with installation of underground systems, which include piping, sewers, duct banks, and grounding grid. The underground piping would consist of service, potable, and firewater distribution. The sewer system would consist of sanitary, oily water and clean stormwater collection systems. The underground piping system may have cathodic protection, as determined by the soil resistivity tests and piping material. [Foundations for major equipment and the cooling tower basin would be constructed.](#)

After the installation of the underground systems and foundations, the excavated areas would be backfilled, compacted, leveled, and gravel-finished [as required](#) for installation of the aboveground portion of the facility.

The main North-South pipe rack would be erected and HRSG [and cooling tower](#) installation would begin ~~with the southernmost unit.~~ The rack would be loaded prior to the arrival of the gas turbines. For each HRSG the respective stacks would be field assembled and erected last. Work in the Water Treatment area would commence with fabrication and installation of tanks. ~~The Air-Cooled Condenser installation would then commence with bank construction proceeding from north to south.~~ The Water Treatment Building would be installed to facilitate the installation of water treatment equipment.

The steel structure for the Steam Turbine [building enclosure](#) would be installed and the [bridge gantry](#) crane assembled and installed prior to the arrival and setting of the steam turbine and generator on their foundation. The heavy haul components would be transferred directly from a nearby railroad spur or barges to the foundations using special transports. ~~The building siding and roof panels would be installed to close the building.~~ The steam turbine transformer is then set in place and the connections made.

The 230 kV Switchyard and the main transmission line work would be started. The installation work would continue as the gas turbines and the generators are being

received and set in place. The gas turbines and the generators would be installed ~~beginning with the southernmost unit closest to the steam turbine~~. After each generator is set on its foundation using heavy haul transport directly from a nearby railroad spur, the main transformer for that turbine and the air intake filter housing would be set in place. The filter housing would be assembled on ground and lifted into place. The interface between the transformers and the switchyard would then be made.

The main East-West pipe rack near ~~the Air-Cooled Condenser, the cooling tower~~, the Control Building, and the power distribution centers with the auxiliary transformers would be installed. The rack would be loaded prior to installing the building. The work on the 69 kV switchyard and existing refinery substations would proceed in parallel with this effort.

After the pipes are welded, inspected and given the appropriate NDE tests, each system is pressure tested prior to turnover for commissioning.

The DCS would be set in the control room. The electrical and instrumentation cables would be pulled and terminated.

At the completion of construction, the final grading of the surfaces would be performed. The roads, parking lot, and other designated areas in the power block, maintenance and warehouse areas will be paved while the balance of the plant area will be finished with a gravel surface ~~as required~~. Gravel surfacing will be provided at the switchyard. All side slopes and embankments shall be protected against erosion with landscaping or be seeded with grasses common to the local area.

13.4.4 Construction Site Security

Site Security plans will be developed prior to mobilization in consultation with BP in order to ensure consistency. Security measures to control and limit access to the job site begins with initial mobilization.

The site contractor's construction office, parking area and laydown area will be secured by fencing. A bonded outside security service agency would supply manpower as deemed necessary to provide 24-hour surveillance. Access to the laydown and construction areas will be controlled. Security assignments will include traffic control for personnel access/egress, gate monitoring for all deliveries, random toolbox checks for material/tool control, after hours security, and fire watch.

Temporary lighting will be provided to ensure safety and security of the site and laydown areas. Lighting will be provided at strategic locations using light fixtures attached to buildings, fences, and poles.

13.5 Construction Approaches

13.5.1 General Construction Methods

The proposed site is generally flat and dry. Waters that do not absorb directly into the ground would normally runoff with the lay of the land toward the north and west. No temporary equipment bridges are expected. Normal construction methods would be

used for the Cogeneration Project. General construction methods would involve site survey and staking, site preparation for runoff control, site excavation, fill and compaction of structural base, installation of structural support piles, construction of reinforced concrete footings and foundations, installation of compressors and other equipment, installation of process piping, installation of electrical systems, erection and finishing of steel buildings, final gravel grading and asphalt paving.

13.5.2 General Construction Equipment

General construction equipment to be used include but are not limited to: heavy, medium and light equipment such as excavator, roller compactors, front end loaders, bulldozers, graders, backhoes, dump trucks, water trucks, concrete trucks, pump trucks, utility trucks, cranes, pile drivers, man lifts, forklifts, lube oil and fuel truck. Table 13.5-1 lists the construction equipment that would be used for construction of the Cogeneration Project.

13.5.3 Utility Connection Construction

A detailed pipe route, survey, and plan have not been prepared at this time. Applicable regulations include DOT 49 CFR-192, which specifies the required depth, fill, and cover for pipelines. In general, pipeline trenches would be dug 6 to 10 feet deep depending on soil conditions and water table. Minimum fill would generally be 3' to 4' over the pipe, but also depends on evaluation of loads from vehicle traffic that may pass over the pipeline at designated points. Trenches would be shored or braced in accordance with WISHA/OSHA requirements.

13.5.4 Best Management Practices for Construction

The proposed site is generally flat. Water that does not absorb directly into the ground would normally runoff with the lay of the land toward the north and west. During construction, silt fences, gravel bags, drainage swales, and ditches will be used to control the flow from the work area to prevent adverse sedimentation or erosion to the undisturbed areas adjoining the site. Runoff will be collected into a perimeter ditch, which feeds a main collection ditch for the Cogeneration facility. Sediment from incidental erosion will be collected by conventional means within the perimeter ditch. Using these measures, the site runoff will be captured and diverted to a treatment and detention system where the silts and fines will be allowed to settle out before water is discharged to the adjoining areas.

Upland surface water runoff will be diverted around the affected areas by means of swales and ditches toward the general area to which they originally drained. Erosion control measures will be installed at all outfall locations to minimize any adverse effects to the undisturbed surrounding terrain. Vegetation will be planted on all permanently exposed sloped areas and ditches to minimize any erosion to these surfaces. Stormwater from construction areas will be routed first to a lined oil/contaminant trap pond before discharging to a final treatment and detention pond. Water from the final treatment and detention pond will be to a receiving wetland and duck ponds. Appendix F Technical Report on Water provides detail on the proposed stormwater treatment and detention system.

As the site is cut and filled to its final elevation, the main portions of the permanent plant stormwater system will be installed and incorporated into the temporary construction stormwater system. The permanent plant system will consist of catch basins, manholes, and an underground stormwater piping system that will discharge to a lined oil/contaminant trap pond before discharging to a final treatment and detention pond. The discharge from the final treatment and detention pond will be to a receiving wetland and duck ponds. Additional details of the final plant operational stormwater treatment and retention are provided in Appendix F: Technical Report on Water.

13.5.5 Construction Waste

The anticipated quantities of Cogeneration Project construction wastes are listed in Table 13.5-2. All wastes will be segregated and placed in appropriate containers for shipment and treatment or disposal. All wastes will be properly managed in accordance with state regulations (WAC 173-303) and recycled or disposed of in a permitted facility.

13.6 Transportation Systems for Construction

Construction materials such as concrete, structural steel, pipe, wire and cable, fuels, reinforcing steel, and small tools and consumables would likely be delivered to the site by truck using existing roadways. Some of these materials could also be delivered by rail. These materials will be segregated and stockpiled in designated locations within the site and laydown area. Fueling of construction equipment and vehicles will be within a designated location with appropriate provision for spill containment. Table 13.6-1 provides an estimate of the vehicle trips expected during the construction of the Cogeneration Project.

Large or heavy equipment would be transported to the site via rail or by barge. Items arriving by barge are likely to be offloaded at Bellingham or Gulf Road in Ferndale and transported to the site either by rail or special heavy haul truck. Rail deliveries would be off-loaded and transported to the site by a heavy-haul contractor using specialized transports. The existing refinery rail spurs would be used to unload heavy equipment transported by rail. These rail spurs would first be checked to ensure they could accept the Cogeneration Project equipment. The major heavy equipment and mode of transport for the Cogeneration Project is listed in Table 13.6-2.

13.7 Commissioning

A full Start-Up and Commissioning Program would transition the Cogeneration Project from the construction phase to commercial operation. At the conclusion of successful performance tests, the Cogeneration Project would be deemed ready for commercial operation.

After the installation of major mechanical and electrical equipment is completed, individual systems would be completed in preparation for testing and commissioning. The commissioning activities would be prioritized on a system-by-system basis, starting with water treatment, power distribution, and natural gas supply systems.

Once these initial systems are prepared for service, the steam piping would be cleaned using high-pressure water. The boiler, boiler feedwater, and condensate piping would

also be chemically cleaned. The resulting waste streams would be collected separately and transported to approved locations for recycling or disposal.

The lube oil systems of all the turbine generators would be filled, flushed, and cleaned. The CGTs, STG and pumps would be aligned and checked. Instrument loops would be checked and verified. Each system would undergo testing and trial runs prior to being put into service. BP would witness and approve critical tests. As each system checkout is completed, the contractor would furnish turnover documentation to BP for walk through and punch list development.

The gas turbines would be started up individually and steam raised in the corresponding HRSG. The steam piping to the STG and the process steam export piping would also be steam cleaned during this period. The gas turbines would then be tuned to meet efficiency and emission performance requirements. The CEMS systems would be tested and calibrated. BP would witness and approve critical tests to ensure proper performance.

The temporary piping modifications required for steam cleaning would be removed and the system restored for operation. The facility would now be ready for operations and performance testing. At the completion of successful performance tests, the facility would be ready for commercial operation and the care, custody, and control of the plant would transfer to BP.

All electrical equipment (i.e., power circuit breakers, power transformers, bus installation, control panels, etc.) would be subjected to acceptance testing at the factory and at the Cogeneration site. Acceptance testing will involve point-to-point wiring and labeling checks, insulation resistance tests, and inspection tests that verify proper assembly and conformance to applicable codes. An operational test of the complete system will be conducted to verify proper installation and functionality. On site and pre-commissioning tests will be coordinated with BPA. Additional details on Cogeneration Project construction schedules, activities, resources, site preparation and procedural descriptions are provided in Section 11 of this Technical Report.

13.8 Construction Management

13.8.1 Construction Management Structure

BP would hire an EPC contractor to design, procure, construct, and commission the Cogeneration facility. This contractor would be responsible for the means and methods of constructing the project within the applicable guidelines and regulations. The EPC contractor would employ direct-hire craft labor as well as subcontractors for certain specialty work as required.

13.8.2 Organization:

The EPC contractor's construction management organization would include field supervisory, support, and construction management personnel (see Figure 13.8-1). Construction management personnel would assure activity management, craft supervision, quality assurance and quality control, industrial relations, field engineering,

materials management, management of subcontractors, timekeeping, payroll and project controls, and environmental, safety and health performance.

The EPC contractor would hold meetings with the contractor's management staff to plan and monitor the work, delivery of materials and staging of materials from the laydown areas. The field supervisors would meet with their crews on a regular basis to detail work plans and tasks.

The EPC contractor would also hold regularly scheduled meetings with the subcontractors to monitor the status of work. The EPC contractor would coordinate its activities with those of subcontractors to mitigate potential interference and disruptions. BP and the EPC Contractor will also meet regularly to monitor and coordinate work at the site.

13.8.3 Approach

The EPC contractor would have the overall responsibility for employing Project direct hire craft labor and subcontractors.

13.8.4 Pre-Construction Planning

The EPC contractor would begin planning activities during the engineering and design phase to ensure timeliness of design documents and material deliveries. These activities would include:

- Evaluation of permit and plan check requirements.
- Development of construction techniques, rigging plans, traffic plans, heavy haul requirements, construction equipment requirements and field staffing plan.
- Development of integrated engineering, construction, and commissioning schedule, including construction sequence.
- Development of field procurement and contracting strategies.
- Constructability review and plot plan finalization.

13.8.5 Construction QA/QC, Environmental Compliance Programs

A Quality Assurance and Quality Control (QA/QC) program would be used during all phases of the project to ensure that all phases of the project are completed as specified. A Project Procedures Manual would be developed to describe how the EPC contractor would implement and maintain QA/QC and Environmental Compliance programs during all phases of the work.

In the QA/QC Program, the contractor would describe the activities and responsibilities within its organization and the measures to be taken to assure all aspects of quality control in the project. Some of the topics that will be covered are design control, configuration management, drawing control, non-destructive examination records, personnel qualifications, and equipment installation.

The Environmental Compliance program will ensure that construction activities meet the conditions and specifications set for environmental standards established in the Site Certification Agreement and other applicable environmental regulations. This program will

also ensure that steps are taken to implement required actions and will measure the effectiveness of these actions.

The EPC contractor will prepare a list of qualified suppliers and subcontractors for equipment purchase orders or services contracts. Qualification criteria may be used in awarding purchase orders or contracts as appropriate. Such criteria may include the supplier or subcontractor prior performance record, financial condition, personnel availability, production capability and quality program. The evaluation of suppliers may also include a survey of the supplier's facilities.

The EPC contractor would inspect and monitor the work of subcontractors to ensure compliance with construction plans, specifications, and documents. Non-conformances would be documented and corrected or mitigated according to the QA/QC procedures.

The EPC contractor will carry out QA/QC activities throughout the construction phase of the project. The EPC contractor's QA/QC staff, composed of professional engineering and construction personnel, will monitor adherence to contract specification and requirements throughout the execution of work.

13.8.6 Construction Operational Control

Construction of the Cogeneration Project must be conducted safely, in a manner that minimizes impacts to the environment and in accordance with applicable regulations. All construction site personnel will have the authority to "Stop Work" if they believe an unsafe condition exists. "Stop Work" orders would also be given if potential historic or cultural artifacts were discovered during site preparation and grading.

13.8.6.1 Safety

The goal of the construction safety program is to have no harm to employees. To meet this goal a very aggressive safety plan will be developed and implemented. Each employee will be required to attend a safety and health orientation. Additional training will be given to the craft throughout the tenure of the project. Other safety program features could include "tailgate" safety meetings to raise crew awareness, hazardous energy lock out/tag out procedures, fall protection and excavation safety procedures, and the use of safe work checklists or other job hazard identification processes. Safety audits will be conducted frequently and a full-time safety engineer will be required to constantly monitor the work processes. The use of appropriate personnel protective equipment will be strictly enforced.

13.8.6.2 Environmental Compliance

As part of the Environmental Compliance program, the EPC contractor will actively manage project construction activities to ensure compliance with applicable laws, ordinances and regulations. Elements of this program include procedures to minimize impacts to soil, water and air as a result of construction activities, as well as documentation and compliance reporting.

Effective construction waste management is an important part of environmental management. Dumpsters, having a capacity of 20–40 yd³, will be utilized to manage non-hazardous construction waste and debris to be disposed of at designated local

disposal facilities. Hazardous construction waste will be managed by licensed companies contracted by the EPC contractor for such special services. Permits will be obtained from the appropriate agencies as required for the transportation and recycling or disposal of hazardous materials.

13.8.6.3 Spill Prevention and Control

BMPs will be implemented to avoid the spill of construction machinery fluids including diesel fuel, gasoline, motor oil, hydraulic fluid, brake fluid, and anti-freeze during construction. A specific area on the site will be designated for servicing the construction equipment including fueling. This will ensure localization of spills and implementation of appropriate control measures. The EPC contractor's responsibility includes training of all construction personnel and subcontractors in spill avoidance and, if spills occur, in containment, clean up, and reporting procedures consistent with established practices and regulatory requirements.

During construction, hazardous materials stored onsite will be limited to paint, coatings, solvents and adhesive materials. These materials will be stored in a locked utility shed or secured fenced area, and conform to OSHA Guidelines. Construction personnel will be trained in handling hazardous materials and alerted to the dangers associated with these materials. A designated on-site Safety Engineer will implement health and safety guidelines and contact emergency response personnel and the local hospital, if necessary. Material Safety Data Sheets (MSDS) for each chemical will be kept on-site and construction employees will be made aware of their location and content.

14. CAPITAL COSTS

At this time the total capital costs for the Cogeneration Project are estimated to be approximately \$580 million, [but this figure is subject to change as the project progresses](#). A summary of the major component cost for the Cogeneration Project is provided in Table 14.0-1.

15. REFERENCES

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